Final advice on base rates SDE+ 2016

C.L. van Zuijlen **(ed)**
S.M. Lensink **(ed)**

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Alongside the editors Christine van Zuijlen and Sander Lensink, the following individuals helped to write this report:
Luuk Beurskens, Michiel Hekkenberg, Carolien Kraan, Marc Londo, Hamid Mozaffarian, Arjan Plomp, Ayla Uslu from the Energy Research Centre of the Netherlands (ECN) , Marcel Cremers, Bart in 't Groen, Gerben Jans, Anne-Marie Taris, Jasper Lemmens, Ronald Meijer, Craig Savy (DNV GL) and Harmen Mijnlieff (TNO).

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Any questions about this Final Advice can be addressed to sde@ecn.nl.

Abstract

ECN and DNV GL have been commissioned by the Ministry of Economic Affairs to study the cost of renewable energy production. This cost assessment for various categories is part of the advice on the subsidy base rates for the SDE+ feed-in support scheme. A draft version of this advice has been discussed with the market in an open consultation round. This report contains the final advice on the cost of projects in the Netherlands targeted for realisation in 2016, covering installation technologies for the production of renewable electricity, renewable gas and renewable heat.

Contents

Executive Summary

The Dutch Ministry of Economic Affairs asked ECN and DNV GL to issue advice on the base rates for the SDE+ 2016 scheme. This report contains the Final Advice on the recommended base rates that have been determined following the consultation of market parties. For geothermal, the advice was provided by ECN, DNV GL and TNO.

The base rates have been calculated so as to be sufficient for the majority of the projects in the relevant category. However, due to project-specific circumstances, t the implementation of some initiatives may turn out to be unprofitable despite the SDE+ allowance.

The resulting SDE+ 2016 base rates for the different categories are shown in Table 1 to Table 6. The designations E, G, H and CHP indicate which category is referred to. i.e. renewable electricity, gas, heat or combined heat and power plants. For comparison, the base rates from the SDE+ 2015 Base Rates Final Advice[1] have also been included in the table. Base rates higher than 0.200 €/kWh have been calculated indicatively and are denoted as > 0.200 €/kWh.

1 https://www.ecn.nl/publicaties/ECN-E--14-035.

Table 1: Advised base rates for SDE+ 2016: hydro-electric, wind and solar energy (amounts in €/kWh)[2]

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours	Advised base rate for SDE+ 2015
Hydropower, height of fall ≥ 50 cm	E	0.173	5,700	0.175
Hydropower, height of fall ≥ 50 cm, renovation	E	0.108	2600	0.067
Free tidal current energy, height of fall < 50 cm	E	>0.200	3700	0.275
Osmosis	E	>0.200	8,000	0.585
Photovoltaic solar panels ≥ 15 kW_p and connection >3x80A	E	0.128	950	0.141
Solar thermal, aperture area ≥ 100 m^2	H	0.103	700	0.137
Onshore wind, ≥ 8 m/s	E	0.070	n/a	0.074
Onshore wind, ≥ 7.5 and < 8 m/s	E	0.076	n/a	0.081
Onshore wind, ≥ 7.0 and < 7.5 m/s	E	0.082	n/a	0.086
Onshore wind, < 7.0 m/s	E	0.093	n/a	0.098
Wind on interconnecting water defences, ≥ 8 m/s	E	0.075	n/a	0.081
Wind on interconnecting water defences, ≥ 7.5 and < 8 m/s	E	0.082	n/a	0.088
Wind on interconnecting water defences, ≥ 7.0 and < 7.5 m/s	E	0.087	n/a	0.094
Wind on interconnecting water defences, < 7.0 m/s	E	0.099	n/a	0.107
Wind on lake, water ≥ 1 km^2	E	0.114	n/a	0.114

Table 2: Advised base rates for SDE+ 2016: geothermal energy (amounts in €/kWh)

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours (power/heat)	Full load hours combined	Heat/power ratio	Advised base rate for SDE+ 2015
Geothermal heat, depth ≥ 500 metres	H	0.056	5,500	-	-	0.052
Geothermal heat, depth ≥ 3500 metres	H	0.062	7000	-	-	0.055
Geothermal co-generation, depth ≥ 500 metres	CHP	0.112	5,000/4,000	4,091	8.00	0.098

2 No full load hours have been included for the categories relating to wind energy because the generic full load hours cap has been abolished since SDE+ 2015.

Table 3: Advised base rates for SDE+ 2016: water purification plants (amounts in €/kWh)

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours (power/ heat)	Full load hours combined	Heat/power ratio	Advised base rate for SDE+ 2015
Waste water treatment plant (WWTP) - thermophilic digestion of secondary sludge	CHP	0.060	8,000/4,000	5,729	0.66	0.061
WWTP - thermal pressure hydrolysis	E	0.093	8,000	-	-	0.095
WWTP (renewable gas)	G	0.032	8,000	-	-	0.034

Table 4: Advised base rates for SDE+ 2016: incineration and gasification of biomass (amounts in €/kWh)

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours (power/ heat)	Full load hours combined	Heat/power ratio	Advised base rate for SDE+ 2015
Biomass gasification (≥ 95% biogenic)	G	0.151	7,500	-	-	0.139
Existing capacity for direct and indirect co-firing	E	0.107	5,000/6,000	5,839	-	0.108
New capacity for direct co-firing	E	0.114	7,000	-	-	0.115
Boiler fired by solid or liquid biomass 0.5-5 MW_{th}	H	0.052	4,000	-	-	0,051
Boiler fired by solid or liquid biomass ≥5 MW_{th}	H	0.043	7,000	-	-	0.043
Boiler fired by liquid biomass	H	0.071	7,000	-	-	0.072
Heat, wood pellets	H	0.057	7,000	-	-	0.054
Thermal conversion of biomass, > 50 MW_{th}	CHP	0.077	7,500/7,500	7,500	2.99	0.084[3]
Thermal conversion of biomass, ≤ 50 MW_{th}	CHP	0.143	8,000/4,000	4,241	2.44	0,144[3]

* In relation to existing capacity for direct and indirect co-firing, 5,000/6,000 stands for 5,000 full load hours of direct co-firing and 6,000 full load hours of indirect co-firing.

[3] In the SDE+2015, the category limit was 10 MW_e.

Table 5: Advised base rates for SDE+ 2016: digestion of biomass (amounts in €/kWh)

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours (power/ heat)	Full load hours combined	Heat/power ratio	Advised base rate for SDE+ 2015
All-feedstock digestion (renewable gas)	G	0.060	8,000	-	-	0.063
Co-generation, all-feedstock digestion	CHP	0.087	8,000/4,000	5,742	0.65	0.095
Heat, all-feedstock digestion	H	0.060	7,000	-	-	0.053
Digestion and co-digestion of animal manure (renewable gas)	G	0.080	8,000	-	-	0.083
Co-generation, digestion and co-digestion of animal manure	CHP	0.121	8,000/4,000	5,732	0.65	0.121
Heat, digestion and co-digestion of animal manure	H	0.083	7,000	-	-	0.080
Digestion of more than 95% animal manure (renewable gas)	G	0.181	8,000	-	-	0.136
Co-generation, digestion of more than 95% animal manure (renewable gas)	CHP	>0.200	8,000	-	-	0.305
Heat, digestion of more than 95% animal manure	H	0.109	7,000	-	-	0.106

Table 6: Advised base rates for SDE+ 2016: existing installations (amounts in €/kWh)

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours (power/ heat)	Full load hours combined	Heat/power ratio	Advised base rate for SDE+ 2015
Extended lifespan, thermal conversion ≤ 50 MW_e	CHP	0.063	8,000/4,000	4,429	1.82	0.064
Extended lifespan all-feedstock digestion, co-generation	CHP	0.086	8,000/4,000	5,855	0.58	0.087
Extended lifespan co-generation, digestion and co-digestion of animal manure	CHP	0.108	8,000/4,000	5,855	0.58	0.108
Extended lifespan all-feedstock digestion (renewable gas)	G	0.059	8,000	-	-	0.064
Extended lifespan all-feedstock digestion (heat)	H	0.056	7,000	-	-	0.058
Extended lifespan digestion and co-digestion of animal manure (renewable gas)	G	0.071	8,000	-	-	0.076
Extended lifespan digestion and co-digestion of animal manure (heat)	H	0.071	7,000	-	-	0.072

1 Introduction

The SDE+ in general

The Stimulation of Sustainable Energy Production scheme (SDE) is used by the Ministry to stimulate the production of renewable energy in the Netherlands. This scheme has been opened annually by the Ministry[4] since 2008 and is opened to applicants in phases, with the lowest cost technologies being eligible for subsidies first. The SDE+ scheme reimburses the difference between the *base rate* (the production costs of renewable electricity, renewable heat and renewable gas) on the one hand and the *correction amount* (the market price of renewable electricity, renewable heat or renewable gas) on the other hand. For each technology, a *base price for energy* is also set. This represents the lower limit for the correction amount. For more details of the scheme and terms used, see Appendix C.

ECN and DNV GL advise on the level of the base rates for the SDE+ 2016 scheme.

Research assignment

As in previous years, the Ministry asked the Energy research Centre of the Netherlands (ECN) and DNV GL for advice on the level of the base rates for the SDE+ scheme for 2016. ECN and DNV GL advise the Ministry on the level of the base rates for the categories prescribed by the Ministry. Ultimately, the Minister of Economic Affairs decides on the opening of the SDE+ scheme in 2016, which categories will be opened and the base rates for new SDE+ allowances in 2016.

It was once again decided with the Ministry to present a draft advice to the market. A round of consultations took place in April and May 2015. A pre-final advice was submitted to the Ministry before the summer and consultations were held on the findings. This report contains the Final Advice on the recommended base rates that have been determined since the consultation of market parties and in coordination with the Ministry in the summer period.
NB: ECN and DNV GL explain in the *Consultatiedocument Basisbedragen SDE+ 2016* (Consultation Document on Base Rates SDE+ 2016) (ECN-E--15-035) how they dealt with the reactions from the market consultations.

[4] The implementation of the SDE+ scheme is the responsibility of Netherlands Enterprise Agency. For more information about the SDE+ scheme itself, see http://www.rvo.nl/subsidies-regelingen/stimulering-duurzame-energieproductie-sde.

Structure of this report

Chapter 2 describes the process of creating this report and the general principles. The findings are then detailed for hydroelectric power (Chapter 3), solar energy (Chapter 4), wind energy (Chapter 5), geothermal energy (Chapter 6), water purification (Chapter 7), thermal conversion of biomass (Chapter 8), digestion (Chapter 9) and existing installations for digestion and thermal conversion (Chapter 10). Each category in the SDE+ has its own section setting out the technical and economic parameters. Chapter 11 ends with conclusions which are translated to base rates.

This report includes the 2016 base rates and the calculation method for the 2016 provisional correction amounts for each category. Appendix B includes an overview of all categories and the accompanying 2016 base prices and 2016 provisional correction amounts. The base rates are explained in more detail in the report *Basisprijzen SDE+ 2016* (Base prices for SDE+ 2016) (Kraan and Lensink, 2015), while the calculations for the correction amounts are in the report *Correctiebedragen t.b.v. bevoorschotting 2016 (SDE+)* (Correction amounts for advances for 2016 [SDE+]).(Lensink and van Zuijlen, 2015).

2

Process and starting points

This chapter describes the process followed and the working method used in section 2.1. The general and financial starting points for this advice are then discussed in sections 2.2 and 2.3.

2.1 Process and working method

Process

On 7 April 2015, a draft advice on the SDE+ base rates was presented for the purpose of a public market consultation. To this end, an information meeting was held for sector organisations at the Ministry of Economic Affairs. Market parties were invited to submit their responses to this draft report to the Energy research Centre of the Netherlands (ECN). By 27 June, approximately 40 responses from the consultations had been received, after which over twenty consultation discussions were held in the period from 23 April to 12 May 2015.

ECN and DNV GL drew up a pre-final advice following the market consultation. The advice for geothermal energy was drawn up by ECN, DNV GL and TNO. This report contains the Final Advice on the recommended base rates that have been determined since the consultation of market parties and in coordination with the Ministry during the summer period.
NB: In the *Consultatiedocument Basisbedragen SDE+ 2016* (Consultation Document on Base Rates SDE+ 2016) (ECN-E--15-035) ECN and DNV GL explain how they dealt with the reactions from the market consultations during the preparation of this Final Advice.

IINAS, the International Institute for Sustainability Analysis and Strategy, has performed an external review of this Final Advice. The authors would like to thank Mr U.R. Fritsche and his colleagues for their valuable comments. The review is included in Appendix D. ECN and DNV GL respond to the review commentary in the afterword (Appendix E).

Working method

The advised base rates comprise the production costs of renewable energy carriers plus any scheme-specific additional costs related to the signing of electricity, heat or gas contracts. The Ministry defined the categories in its original request for advice. For all categories, ECN and DNV GL have calculated the production costs of renewable electricity, renewable gas or renewable heat. The Minister of Economic Affairs makes the final decision on when categories are opened. Neither the inclusion nor the absence of a category in this report may be interpreted as a recommendation for a potential opening.

2.2 General starting points

The rule of thumb is that the majority of the projects should be able to proceed with these base rates.

Legislative and regulatory framework

The starting points for the calculation of the base rates were determined in discussions between the Ministry, ECN and DNV GL. The effectiveness and efficiency of the SDE+ incentive scheme were taken into account. The SDE+ allowances, and hence the base rates, must be high enough to enable production of renewable electricity, renewable heat and renewable gas, but need not be sufficient for all planned projects. The rule of thumb is that the majority of the projects in each category should be able to proceed with these base rates.

Existing laws and regulations must be taken into account when calculating the production costs, insofar as these apply generally in the Netherlands. The advice is thus based on policy that will be in force in 2016, in accordance with decisions taken up to this point. The production costs relate to projects that are eligible for SDE+ in 2016 and can begin as construction projects in 2016 or early 2017. The Ministry ensures that the calculated production costs comply with the provisions of the European Commission on state subsidies.

Reference installation and system delineation

ECN and DNV GL have defined a reference installation for each category. The reference installation consists of a particular technology or combination of technologies combined with a typical number of full load hours. A reference fuel or substrate is included for bio-energy categories. In the opinion of ECN and DNV GL, the reference installation has a typical configuration for new projects in the category to be investigated.. The technical-economic parameters are quantified for the defined biomass-technology combinations. Based on these parameters, the production costs and base rates are calculated with the help of a simplified cash flow model, which can be consulted on the ECN website[5].

The SDE+ scheme reimburses the difference between the correction amount and the base rate. The correction amount is a measure of the market price of the renewable electricity, heat or gas. The base rate is a measure of the production costs of renewable electricity, renewable heat and renewable gas. The production costs are the (additional) costs involved in generating renewable energy.

5 https://www.ecn.nl/nl/projecten/sde/sde-2016.

The definition of 'additional costs,' i.e. the system boundary, can significantly influence the calculated biomass costs, especially in systems that derive the biomass from waste flows or residual products. In these systems, calculations are made of the additional costs of utilising these flows or products for the production of renewable electricity or renewable gas. Biomass costs are based on the prices that need to be paid to get the biomass delivered to the installation. Additional costs are determined by calculating the difference between the biomass prices referred to above and the price of biomass if it were not used for the production of renewable electricity, renewable heat or renewable gas. All prices stated in this report exclude VAT.

For renewable heat categories, the costs relating to the production of renewable heat are considered for subsidy. The cost of an optional heat distribution pipe is regarded as part of the project investment costs. The heat infrastructure on the demand side, such as a heat grid, is not part of the costs eligible for subsidy. The heat production considered in this advice relates to the heat throughput directly behind the gate of the installation, but before the heat distribution pipe. This means that an SDE+ allowance may also apply to internal use of renewable energy, as long as it is not intended for the production process itself.

A heat grid is not included in the costs eligible for subsidy, but heat transport pipes are included.

A new Ministerial Decree on Gas Quality (*Ministeriële Regeling Gaskwaliteit*)was published in July 2014. For the purpose of the investment and O&M costs of gas upgrading, the extra gas analyses that have been necessary since 1 October 2014 to comply with this Ministerial Decree on Gas Quality) have been taken into account for new projects.

Units

For the SDE+ 2016, the base rates for all the categories are stated in € per kWh. In the past, figures for the heat and renewable gas options were shown in € per GJ and € per Nm^3. Table 7 shows the conversion factors used.

Table 7: Conversion factors for base rates (in € per kWh)

	Unit for base rate		Multiplier	Formula
	From	To		
Heat	[€/GJ]	[€/kWh] (final)	0.0036	(Amount in €/kWh) = (Amount in €/GJ) x (3.6 MJ/kWh)/(1,000 MJ/GJ)
Green gas	[€ct/Nm^3]	[€/kWh] (final)	0.0010236	(Amount in €/kWh) = (Amount in €ct/Nm^3) x (0.01 €/€ct) x (3.6 MJ/kWh)/(35.17 MJ/Nm^3)

2.3 Financial starting points

The financing of renewable energy projects fluctuates. Not only do the renewable energy technologies change as a result of learning and innovation, but practical experience can also cause the perceived risk of projects to change. In principle, higher risk means higher capital costs. The cost of attracting loan capital is moreover subject to increased economic fluctuations over which the renewable energy sector has no control.

The financial parameters that are used to calculate the base rates are shown in Table 8 and explained further in the text below. In the opinion of ECN and DNV GL, the results of these parameters provide a general picture of the capital costs of SDE+ projects. This does not mean that SDE+ projects cannot be financed differently in practice.

Table 8: Financial parameters used for SDE+ 2016

Financial parameter	Value used	Explanations
Interest with green funding	4.5%	Solar PV, solar thermal, geothermal, gasification, hydropower
Interest without green funding	5.0%	Other categories
Ratio of loan capital (LC)/equity (E)	90% LC / 10% E	Solar PV
	80% LC / 20% E	Onshore wind
	75% LC / 25% E	Wind on lake
	70% LC / 30% E	Other categories
Return on equity	15%	Categories with a high risk profile
	12%	Other categories
Inflation in biomass prices and O&M costs	1.75%/year	

Interest

ECN and DNV GL began the study for the Final Advice by reflecting on the parameters used last year. The interest rate at which projects can take out loans will probably be higher for future projects than the 5.5% used last year. An interest rate of 4.5% is currently achievable for many projects, but there are signs that interest rates will rise again. Green funding offers the project developer a discount of between 0.5% and 0.8%.

The interest on loans has fallen in recent years, but a turning point appears to have been reached. Nevertheless, ECN and DNV GL think that a further fall in interest rates by 0.5% is in line with their previous cautious approach to interest rates for the purposes of the advice on base rates. This yields a rate of 5.0% interest on loans for projects without green funding. For projects with green funding, a 0.5% reduction has been assumed, bringing down the effective interest rate to 4.5%. The market consultation has revealed that there are indeed opportunities to utilise the benefits of green funding for new projects.

Ratio of loan capital/equity

Financial institutions are demanding a larger contribution in terms of equity than in the years before the crisis. This increased contribution is not due to an alternative method of risk assessment, but rather a different policy on risk exposure. The equity shares seen in sustainable energy projects in the Netherlands, which have recently been financed or for which finance has recently been agreed, range from 10% to just over 40%. A target value of 30% equity has been used in the calculations, except for the wind energy category, for which the market consultation has revealed that 20% equity is a typical value for financing. Another exception is solar PV, because the lenders are very diverse; cases where the owner contributes 10% equity come closest to classic project financing.

Equity shares range from 10% to over 40%.

Return on equity

The return on equity used for calculation purposes is 12%. For a few categories with a significantly higher risk, the return on equity has been set at 15%. These are projects for which it is difficult or impossible to conclude long-term biomass contracts, innovative categories and categories whose cash flow is less predictable, such as wind energy. For projects with a significantly higher risk, higher interest rates are demanded for loans. In order not to make too great a differentiation in the underlying parameters, ECN and DNV GL have chosen to factor the effect of the risk profile on interest rates in the return on equity. The financial return must also cover the preparation costs. The preparation costs have not been included in the total investment amount.

Depreciation period

For biomass categories, a subsidy period of twelve years is assumed, compared to fifteen years for the other categories. The term of the loan and depreciation periods are assumed to be equal to the subsidy period. Any payments of the SDE+ allowance after twelve or fifteen years, as a consequence of any banking[6] in the SDE+, have not been included in the calculation. In practice, some of the components of particular technologies have a much longer lifespan than fifteen years. In such cases, their investment costs have been corrected for the remaining value of the components after fifteen years. In the case of project financing, the lender may want the loan to be repaid over a shorter period in practice, e.g. eleven or fourteen years. This offers the lender greater certainty that the loan will be repaid in full.

Capital costs

The total financial return is considered to be reasonable compensation for the total risk of the project. The manner in which the risks and returns are divided between the lender and the project developer has no bearing on the base rates advised under the stated research starting points. Table 9 shows the resulting capital costs (clustered categories) for each theme.

The apportionment of risks and returns between the lender and project developer has no bearing on the base rates.

6 It is possible to transfer eligible production that has not been utilised to a subsequent year. This is known as 'banking'. After the regular subsidy period, the producer of renewable energy can be given one more year to make up for any production not utilised.

Table 9: Weighted average cost of capital (WACC) per theme for SDE+ 2016

Theme	Weighted average cost of capital (WACC)
Hydropower Free tidal current energy	6.0%
Osmosis	6.9%
Photovoltaic solar panels	4.2%
Solar thermal	6.0%
Wind energy - onshore and on interconnecting water defences	6.0%
Wind energy on lake	6.6%
Geothermal heat	6.9%
WWTP	6.2%
Biomass gasification	6.9%
New capacity for direct co-firing Boiler fired by solid or liquid biomass	6.2%
Heat, wood pellets Thermal conversion of biomass	7.1%
All-feedstock digestion	6.2%
Digestion and co-digestion of animal manure	7.1%
Digestion of more than 95% animal manure	6.2%

2.4 Scheme-specific deductions

The nature of the SDE+ scheme implies additional costs for project owners for the duration of the project. These additional costs arise due to choices as to how the SDE+ scheme is structured. For example, the SDE+ scheme basically covers price risks, provided that the parties sell their renewable energy on comparable exchanges. For electricity, this is the day-ahead market, whereas for gas it is the year-ahead market. The trading on these exchanges involves transaction costs, which are charged at €0.0009/kWh. This value is derived from trading on the APX. In addition, while the SDE+ scheme does remove the price risk of fluctuating gas and electricity prices, it does so only to a lower limit. If electricity or gas prices are very low, the SDE+ scheme will no longer compensate the full financial gap. Accordingly, the risk of very low energy prices lies with the projects themselves. The price of this risk, or the costs of insuring this risk within private energy sale contracts, is referred to in this report as the base price premium. As described in Kraan and Lensink, 2015, the basic rate premiums amount to 0.002 €/kWh for the electricity options (including solar and wind) and 0.000 €/kWh for gas and heat.

There are also contract or transaction costs that vary for each category, with the costs for green gas deliveries also being dependent on the pressure of the gas network into which the green gas is fed. The contract costs amount to 0.0009 €/kWh for electricity, 0.001 €/kWh for all-feedstock digestion, 0.002 €/kWh for the digestion and co-digestion of animal manure and 0.01 €/kWh for a green gas hub with different suppliers of crude biogas to one gas input operator.

3

Hydropower findings

This chapter describes the findings for the following categories related to hydropower:

- Hydropower, height of fall ≥ 50 cm (3.1).
- Hydropower, height of fall ≥ 50 cm, renovation (3.2).
- Free tidal current energy, height of fall < 50 cm (3.3).
- Osmosis (3.4).

3.1 Hydropower, height of fall ≥ 50 cm

The Netherlands is a relatively flat country, which means that the fall of rivers in the Dutch delta is small. Nevertheless, existing civil works and engineering constructions in rivers can create sufficient heights of fall to be used for electricity generation in hydroelectric power stations. In practice, this generally ranges from three to six metres, but it can rise to eleven metres in exceptional situations.

Potential projects within the hydropower category are characterised by a wide range of investment costs and corresponding base rates. For this reason, the base rates in this advice report are based on specific projects, with the potential to implement the project as well as the costs of the project being decisive in being selected for subsidy. For the 'hydropower, height of fall ≥ 50 cm' category, the reference installation is based, as before, on a height of fall of less than five metres.

The base rate is above 15 €ct/kWh. The technical-economic parameters on which this base rate is based are provided in Table 10. These have not changed compared to last year.

Table 10: Technical-economic parameters for hydropower, height of fall ≥ 50 cm

Parameter	Unit	Advice 2016	Total amount for reference
Installation size	[MW]	1.0	
Full load hours	[h/a]	5,700	
Investment costs	[€/kW$_e$]	8,000	€8.0 million
Fixed O&M costs	[€/kW$_e$/a]	100	€100,000 / year

Table 11 shows the base rate and several other subsidy parameters.

Table 11: Summary of subsidy parameters for hydropower, height of fall ≥ 50 cm

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.173
Base price for SDE+ 2016	[€/kWh]	0.039
Provisional correction amount 2016	[€/kWh]	0.042
Calculation method for correction amount	APX	

3.2 Hydropower, height of fall ≥ 50 cm, renovation

The cost of generating electricity from hydropower comprises not just the cost of the technical energy installation, but also additional provisions required by laws and regulations in the construction of a hydropower installation. The most important laws and regulations regarding fish kill near engineering constructions are contained in the European Water Framework Directive of 2000, the Benelux Decree on Free Fish Migration, which was revised in 2009, and the European Eel Regulation. The Ministry of Infrastructure and the Environment's *Beheer- en ontwikkelplan Rijkswateren 2016-2021* (national waters management and development plan 2016-2012), which is currently in draft stage, will work out these laws and regulations for the waters managed by Directorate General of Public Works and Water Management (*Rijkswaterstaat*). This plan includes target values for fish kill near existing hydropower plants, which means that fish protection measures need to be implemented.

For the 'hydropower, height of fall ≥ 50 cm, renovation' category, it is assumed that the existing turbines will be replaced by models that are more fish-friendly. At present, an innovative fish-friendly turbine of this kind would appear to be the primary manner of meeting the stricter requirements in terms of fish kill. It is very likely that during such a renovation, some or all of the electrical infrastructure such as the generator, transformers and controls, will need to be modified. It is assumed that there will be no required modifications to the civil engineering structures.

The 'full load hours' parameter in this category has changed compared to the advice for the SDE+ scheme in 2015. The number of full load hours in this category is dependent on project-specific characteristics, such as flow rate and number of turbines. For the forthcoming projects, the number of full load hours is lower than assumed in the draft advice, resulting in an increase in the base rate. The other parameters have remained the same compared to the values used for the SDE+ scheme of 2015. A summary of the technical-economic parameters for the reference installation is shown in Table 12.

Table 12: Technical-economic parameters for hydropower, height of fall ≥ 50 cm

Parameter	Unit	Advice 2016	Total amount for reference
Installation size	[MW]	1.0	
Full load hours	[h/a]	2,600	
Investment costs	[€/kW$_e$]	1,600	€1.6 million
Fixed O&M costs	[€/kW$_e$/a]	80	€80,000/year

Table 13 shows the base rate and several other subsidy parameters.

Table 13: Summary of subsidy parameters for hydropower, height of fall ≥ 50 cm, renovation

Hydropower, height of fall ≥ 50 cm, renovation	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.108
Base price for SDE+ 2016	[€/kWh]	0.039
Provisional correction amount 2016	[€/kWh]	0.042
Calculation method for correction amount	APX	

3.3 Free tidal current energy, height of fall < 50 cm

The advice of last year was mainly based on inshore free tidal current energy: projects being realised in or close to engineering constructions such as sea defences or semi-permeable dams that use the existing tidal movement. Two permits have been issued for the Eastern Scheldt storm surge barrier based on utilisation of tidal energy from free tidal movement. Last year's advice has been largely incorporated into the advice for the SDE+ scheme in 2016. Prompted by the market consultation and innovations in the market, the number of full load hours has been adjusted upwards for this category. The base rate for this category is above 20 ct/kWh.

Table 14 shows the technical and economic parameters used for energy from free tidal current.

Table 14: Technical-economic parameters for free tidal current energy, height of fall < 50 cm

Parameter	Unit	Advice for 2016	Total amount for reference
Installation size	[MW]	1.5	
Full load hours	[h/a]	3,700	
Investment costs	[€/kWe]	5,100	€7.7 million
Fixed O&M costs	[€/kWe/a]	155	€233,000/year

Table 15 shows the base rate and several other subsidy parameters.

Table 15: Summary of subsidy parameters for free tidal current energy, height of fall < 50 cm

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	> 0.200
Base price for SDE+ 2016	[€/kWh]	0.039
Provisional correction amount in 2016	[€/kWh]	0.042
Calculation method for correction amount	APX	

3.4 Osmosis

The first studies into osmosis energy in the Netherlands were performed by KEMA in 2003. These studies focused primarily on the development of membranes for RED (reversed electrodialysis). This led to further studies and the creation of Wetsus (a research institute focusing on sustainable water) and Redstack. The goal of the latter is to construct commercial RED power plants in order to produce energy. To date, Redstack has built a pilot plant near the 'Afsluitdijk' (IJsselmeer Barrier Dam) which generates several tens of kilowatts. The technology is in the development phase, which means the price at which components are available is not based on a free, liquid market. As the technology is still in the development stage, there is still much uncertainty about costs in this category.

The EU FP7 REAPower project was completed in 2013 (Sikkema, 2013). This project led to the creation of a small-scale model for demonstration purposes in Sicily, Italy. Project partners from the Netherlands included Redstack, KEMA and Fujifilm. Fujifilm is conducting studies into the commercial production of the RED membranes.

As the technology is still in the development stage, there is much uncertainty about costs in this category.

Much attention with regard to the development of RED membranes is being focused on reducing the cost price and increasing the energy density (W/m^2). The reference price for commercial membrane is between 2 and 15 €/m^2 with an energy density of between 2 and 5 W/m^2. The range in values reflects future price developments.
The cost price and energy density of RED membranes are decisive factors in the investment costs of RED power plants, particularly as the technology is still in the very early stages of development. In 2007, the price of membranes for RED power plants was 100 USD/m^2 (Turek et al., 2007). Based on recent research (Daniilidis, 2014), the current price has been assumed to be 50 €/m^2 . In the same study, a figure of 60 €/m^2 is

quoted as the most realistic reference price required to make a positive case for an RED power plant in the Netherlands.

Setting the cost price for pilot scale in 2015

In order to determine the cost price of an RED power plant, the current membrane price has been used. This is estimated at 50 €/m^2. As membranes with a power density of 5 W/m^2 are not yet commercially available, calculations are based on 2.2 W/m^2 (Daniilidis et al., 2014) for two examples (see Table 16).

Table 16: Cost structure of RED in the Netherlands and REAPower application based on optimum membrane price

Costs	RED in the Netherlands (Daniilidis)	RED in REAPower
Membrane price (€/m^2)	50	50
Power density (W/m^2)	2.2	2.2
Stack price (€/m^2)	4*	4
Module price (€/kW)	24,545	24,545
Pre-treatment costs (€/kW)	1,850	262
Pump and construction (€/kW)	1,656	569
Personnel costs	1,445	695
Investment costs (€/kW)	29,496	26,071

*estimate based on REAPower cost breakdown

If 60 €/m^2 is used for the calculations, the investment costs amount to 34,042 €/kW and 30,617 €/kW respectively, according to the Daniilidis and REAPower case. If a capacity density of 2 W/m^2 (Molenbroek 2007) is assumed, the investment cost is 36,951 €/kW for the Daniilidis case.

The personnel costs are reflected in a surcharge percentage (20%) on the hardware costs. The price surcharge is based on expected commercial prices in the future rather than current or optimum membrane prices. It is not anticipated that the storage costs will also rise as a result of higher membrane prices.

Due to the fact that the technology is currently at the development stage, and taking into account the fact that there is no transparent, commercial market for the membranes, the cost estimate for this category is more uncertain than for other categories. The investment costs range between approximately 25,000 €/kW and 37,000 €/kW for an osmosis power plant (making use of saline industrial process water or freshwater-to-seawater-transition). Given that there are still steps in innovation that must be completed before the technology can be used on a commercial scale, the top of this bandwidth has been chosen to calculate the base rate.

Table 17 shows the technical-economic parameters for osmosis.

Table 17: Technical-economic parameters for osmosis

Parameter	Unit	Advice for 2016	Total amount for reference

Installation size	[MW]	1.0	
Full load hours	[h/a]	8,000	
Investment costs	[€/kW$_e$]	37,000	€37.0 million
Fixed O&M costs	[€/kW$_e$/a]	213	€213,000/year

Table 18 shows the base rate and several other subsidy parameters.

Table 18: Summary of subsidy parameters for osmosis

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	> 0.200
Base price for SDE+ 2016	[€/kWh]	0.039
Provisional correction amount in 2016	[€/kWh]	0.042
Calculation method for correction amount	APX	

4

Solar energy findings

This chapter describes the findings for the following categories related to solar energy:
- Photovoltaic solar panels ≥ 15 kW_p and connection> 3x80A (4.1).
- Solar thermal, aperture area ≥ 100 m^2 (4.2).

4.1 Photovoltaic solar panels, ≥ 15 kW_p and connection >3×80A

Reference installation

The reference installation for photovoltaic systems (PV systems) ≥ 15kW_p in this advice has changed since the advice for SDE+ 2015. The reference is now a 250 kilowatt peak (kW_p) roof-based system. This choice ties in with the observed increase in the average system size of applications in the SDE+ scheme.

The reference installation for photovoltaic systems in this advice has changed since the previous advice for the SDE+ 2015.

PV systems are modular in nature and as a result can be set up in a wide range of system sizes, from a few kW_p to several MW_p. The system size depends on the capacity of each panel and the number of solar panels that are set up on the available area.

Due to economies of scale in purchase and installation, larger systems generally have lower investment costs per kW_p than smaller systems. However, these economies of scale can also be utilised when installing several small systems at the same time. It therefore serves little purpose to make a distinction between categories based on size.

In previous years the advice was based on a configuration under the most favourable conditions in the Netherlands, which translated to an annual production of 1,000 kWh/kW_p. This research framework no longer applies to this advice. The average annual solar irradiation is not the same across the country. Dropping this criterion thus results in an approach that better matches the majority of projects in the Netherlands. However, this advice does assume that a location is chosen in which panels can be set up in their optimum position, without negative production effects caused by shade, for example. This advice is therefore based on a system with an average annual production of 950 kWh/kW_p as a typical average for current new systems.

The average annual production has been adjusted from 1,000 to 950 kWh/kW_p as a typical average for current new systems.

Field-based systems
The Netherlands does not have much experience with large field-based systems. As a result, the available data for these systems is extremely limited. This advice assumes that the reference chosen is also representative for field-based systems. Compared to roof-based systems, field-based systems are associated with both cost benefits and drawbacks. As the area available for field-based systems is generally larger than for roof-based systems, field-based systems generally have a higher capacity and corresponding cost benefits. However, this is not true in all cases, as there are instances of smaller field-based systems and larger roof-based systems. A study into the profitability of solar power in Germany (ZSW, 2014) shows that the investment costs for the substructure in large field-based systems (5 MW) are up to 50% lower per kW_p than in roof-based systems. However, scale also plays a role here. When implemented on a smaller scale, field-based systems can actually be more expensive than roof-based systems. This is due to additional costs for mounting, building costs and security. For roof-based systems, this advice assumes that no costs need to be incurred for the use of the roof.

Network connection
In the chosen reference case, it is assumed that the project can make use of an existing network connection. For larger systems, there is not always a suitable connection directly in the building or on the site where the system is built. In these cases, it is assumed that a suitable connection is used in a neighbouring building. Where this is not the case, it will result in additional costs, which will be significant for large systems.

Price developments
To be granted a subsidy under the SDE+ 2016 scheme, the applicant must place the orders for the supply of components and for the construction of the production installation within one year after the decision. As the order process for solar PV systems has a limited throughput time, this calculation is based on the expected price level for orders placed in 2017.

The development of prices for PV systems in the years to come is uncertain. In 2011 and 2012, there was an extremely sharp fall in the price of PV modules, but since then prices have been decreasing much more moderately. The market inventory conducted in 2014 by the Dutch solar energy monitoring foundation (*Stichting Monitoring Zonnestroom, 2014*) revealed a wide range in module prices. In this draft advice, it has been assumed that a favourable price is agreed for SDE+ projects. In mid 2013, the European Union agreed a minimum price and a maximum trading volume with Chinese PV manufacturers for solar panels from China. Parties that do not comply with this agreement will be subject to an anti-dumping import levy. The minimum price was amended as of 1 April 2014 on the basis of price changes in the market from 0.56 €/W_p to 0.53 €/W_p. As of 1 April 2015, the minimum price was raised again to 0.56 €/W_p, owing to the weak euro. This mechanism implies that cost prices as a result of technological developments can continue to fall. (ZSW, 2014) demonstrates that the average price of panels from China has settled at a level slightly above marginal costs over the past year. Since the levy was introduced, the prices of modules from Europe and Japan have come ever closer to meeting the Chinese module prices. Worldwide, the installation of PV systems is still moving forwards in leaps and bounds. Based on the historic growth curve, a learning effect of approximately 19% may be assumed if the worldwide production of solar panels were doubled. There is still overcapacity in the production process, although this is smaller than before. In light of both these aspects, it is expected that module prices will fall further at a moderate rate in the years to come.

Prices of other components, such as transformers, have also fallen in recent years. The price of the transformer is highly dependent on the size of the system; for the chosen reference size, the price is around 0.13 €/W_p. For the transformer, we see a learning effect of 10% each time capacity is doubled. The price of other components, such as mounting equipment, cabling and labour, is assumed to fall as a result of the increased efficiency of solar panels. In this draft advice, it is assumed that the prices of the different components will fall further along the learning curve compared to last year's advice. This means an annual price fall of approximately 5% for modules and 2.5% for transformers, installation equipment and labour costs.

Cost parameters

Information from various sources reveals that the total investment costs of roof-based turnkey systems with a size of approximately 250 kW_p were approximately 1,100 €/kW_p in 2014. Taking a modest further price fall and inflation into account, this draft advice assumes a price level of approximately 1,010 €/kW_p in 2017. This figure is based on an average reduction in power over the duration of the subsidy of 0.7% per year.

Little practical information is available about maintenance and management (O&M) costs for solar systems. As a rule, a figure of 1% to 2% of the investment sum is used. The advice assumes an amount of seventeen euros per kW_p for O&M, similar to last year's advice. It is assumed that this amount includes all maintenance, cleaning, insurance of the installation, extension of the guarantee period of the transformer and the management and other operational costs of the installation. Costs related to the existing or future connection are assumed to remain constant.

Finance

There is a noticeable difference in financing conditions for solar PV projects due to a large variation in the type of applicants for these projects. In general, however, solar PV projects are easy to finance. For this reason, this advice assumes a ratio of loan capital to equity of 90:10. If green funding is used, an interest percentage of 4.5% on the loan is assumed, along with a required return on equity of 12%. This corresponds to a base rate of 12.8 €ct/kWh. The technical-economic parameters are summarised in Table 19.

Table 19: Technical-economic parameters for roof-based solar PV

Parameter	Unit	Advice for 2016	Total amount for reference
Installation size	[MW_p]	0.250	
Full load hours	[h/a]	950	
Investment costs	[€/kW_e]	1,010	€253,000
Fixed O&M costs	[€/kW_e/a]	17	€4,250/year

Table 20 shows the base rate and several other subsidy parameters. The base rate has been calculated using expected electricity prices between the trading hour blocks of 8:00 AM and 11:00 PM, with an allowance also being made for the imbalance costs.

Table 20: Summary of subsidy parameters for photovoltaic solar panels ≥ 15 kW_p and connection >3x80A

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.128
Base price for SDE+ 2016	[€/kWh]	0.035
Provisional correction amount in 2016	[€/kWh]	0.044
Calculation method for correction amount	APX (between 8:00 AM and 11:00 PM) x imbalance factor	

4.2 Solar thermal, aperture area ≥ 100 m²

According to the revised Renewable Energy Monitoring Protocol (RVO/CBS [Netherlands Enterprise Agency/Statistics Netherlands], 2015), the annual production of solar heat by a collector per kW amounts to 749 kWh, i.e. 749 full load hours. This is based on a solar thermal system for hot tap water and is independent of size (see section 4.2.2 on page 12 of the Protocol). However, system and standstill losses are not considered in the Protocol, whereas they are in the SDE+. For the SDE+, the system limit is located between the power generating device and the use of the heat; for solar thermal, this is behind the hot water storage tank. As such, there is no reason to change the number of full load hours for solar thermal installations: the number of 700 hours/year will be retained.

The heat output of solar thermal systems varies with the seasons. For the scale size of the systems in the SDE+, long-term heat storage (over several months) is not the obvious solution. In order to still make full use of the heat produced in the summer months, the dimensions of systems are generally based on the demand for hot tap water, which is virtually constant over the year.

The calculation of the SDE+ allowance is based on the difference between the base rate and the correction amount. In order to determine the correction amount, a reference installation is assumed with an alternative consumption of up to 170,000 m^3 per year, which means that the high energy tax rate must be taken into account. However, the level of environmental taxes which energy users pay for gas depends on the quantity they consume. Up to a particular quantity (170,000 m^3 per year), a high energy tax rate applies. As a result, the SDE+ allowance (base rate minus correction amount) is not always sufficient for users with a natural gas consumption of over 170,000 m^3 per year (due to the low energy tax rate above that limit). In order to bring the SDE+ more into line with the majority of solar thermal systems, the size of the reference installation has been increased to 200 m^2. This implies not only a different base rate but also a different calculation method for the correction amount.

For the existing large solar thermal systems in the SDE+ (2012-2015), with collector surface areas above 100 m^2, the investment amount is determined at 700 €/$kW_{th, output}$ (490 €/m^2). It is expected that the costs will fall further at increased system size up to 200 m^2. For this size class, we observe investment costs between 429 €/$kW_{th, output}$ (300 €/m^2) and 857 €/$kW_{th, output}$ (600 €/m^2); the reference value chosen for the investment

Although there are still economies of scale above 200 m^2, they are smaller.

costs of solar thermal systems in the SDE+ from 200 m^2 is 600 €/$kW_{th, output}$ (420 €/m^2). Although there are still economies of scale above 200 m^2, they are smaller.

The total annual O&M costs (fixed and variable) are estimated at approximately 0.2% of the investment costs. The electricity required to supply the circulation pump was never explicitly included in previous versions of SDE+ calculations. This auxiliary energy is estimated at 5 kWh/m^2 annually (SenterNovem, 2006). For a 200 m^2 system this is 1 MWh/year. At an electricity price of 10 cent/kWh, this means an extra cost factor of 100 €/year. This has been added to the annual O&M costs. Variable maintenance costs are no longer included in this advice; these have been accounted for in the annual O&M costs.

Table 21 shows the base rate for a system with a 200 m^2 collector surface area.

Table 21: Technical-economic parameters for energy from solar thermal (200 m^2, 140 kW, investment costs 600 €/kW)

Parameter	Unit	Advice for 2016	Total amount for reference
Installation size	[MW]	0.14	
Full load hours	[h/a]	700	
Investment costs	[€/kW_{th_output}]	600	€84,000
Fixed O&M costs	[€/$kW_{th\_output/a}$]	1.9	€268/year

Table 22 shows the base rate and several other subsidy parameters.

Table 22: Summary of subsidy parameters for solar thermal, aperture area ≥ 100 m^2

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.103
Base price for SDE+ 2016	[€/kWh]	0.025
Provisional correction amount in 2016	[€/kWh]	0.031
Calculation method for correction amount	(TTF [Title Transfer Facility] + energy load)/gas boiler efficiency	

5

Wind energy findings

This chapter describes the findings for the following categories related to wind energy:
- Onshore wind (5.1).
- Onshore wind, one-to-one replacement (5.2).
- Wind on connecting water defences (5.3).
- Wind on lake, water ≥ 1 km^2 (5.4).

As agreed with the Ministry, no base rates have been calculated for the 'onshore wind, one-to-one replacement' category. A brief explanation is given in section 5.2.

5.1 Onshore wind

5.1.1 Starting points and calculation method

The Ministry’s starting points
The Ministry has issued the following general starting points for the SDE+ 2016 in respect of the categories related to wind energy:
- Wind differentiation according to municipal boundaries, as introduced for the SDE+ 2015;
- No generic full load hours cap, as for the SDE+ 2015;
- A further 10% reduction in land costs compared to last year's advice;
- Participation costs are not included in the calculation of the base rate.

The wind differentiation is based on the wind map generated for the SDE+ by KNMI in 2014 (Geertsema and Van den Brink, 2014). Based on The Royal Netherlands Meteorological Institute's (KNMI) wind map, four wind speed categories have been defined for municipalities, as shown in Figure 1.

Table 23: Definition of wind speed categories for wind energy

Category	Wind speed at 100 metres altitude [m/s]
I	≥ 8.0
II	7.5 - 8.0
III	7.0 - 7.5
IV	< 7.0

Calculation method and assumptions
Different starting points have been used and assumptions made for the wind energy calculations for the SDE+ 2016. The resulting technical-economic parameters are shown in Table 24. The parameters are explained further in the text below.

Table 24: Technical-economic parameters for wind energy on land

Parameter	Unit	Advice for 2016	Total amount for reference
Size of the reference wind farm	[MW]	50.0	
Investment costs	[€/kW$_e$]	1,290	64.5 million euros
Fixed O&M costs	[€/kW$_e$/a]	12.4	620,000 euros/year
Variable O&M costs	[€/kWh]	0.0139	

General starting points
Similar to last year, an average-sized wind farm of 50 MW has been assumed for all four wind speed categories for the onshore wind calculations.

Investment costs: turbine prices and additional costs
In order to determine the base rates for the onshore wind energy categories, different wind turbine types with corresponding investments have been used (including the cost of transport, construction and cranes). ECN and DNV GL note a fall of approximately 5% in turbine prices this year. Besides the turbine price, there are additional costs of foundations (including piles), electrical infrastructure on the wind farm, connection to the grid, civil infrastructure, building interest and CAR (Construction All Risk) insurance during construction. The percentage of additional costs has been kept the same as last year, i.e. 33% of the turbine costs. This brings the total investment costs to 1,290 €/kW.

OPEX: variable and fixed operating costs
The variable costs, except land costs, include guarantee and maintenance contracts and are approximately 1.0 €ct/kWh. ECN and DNV GL observe an increasing trend for these costs to be offered on the basis of a fixed price per turbine rather than a variable price per kWh. On average, these prices lie within the range of 20-30 €/kW. Both the variable and fixed costs of guarantee and maintenance contracts are calculated in the model.

The land costs are additional to the stated variable costs. Since the SDE+ 2014, ECN and DNV GL have assumed an annual reduction in land costs of 10% on the Ministry's instructions. As a result, land costs have been set at 0.39 €ct/kWh for the SDE+ 2016. Unlike the previous two years, cautious signals were received during the market consultation this year that this fall in land prices is slowly working its way through to the market. However, the fall is lagging behind the fall in the SDE+ and is not acknowledged by all market parties. In any event, ECN and DNV GL conclude that 0.39 €ct/kWh does not yet represent the actual cost of land for wind projects.

The fixed annual costs have been reduced from 15.3 €/kW to 12.4 €/kW (particularly as a result of lower insurance costs).

The fixed annual costs are those of public liability insurance, machinery breakdown insurance, standstill insurance, network maintenance, energy use, property tax, and management and maintenance of land and roads. In this advice, ECN and DNV GL have assumed lower fixed annual costs than in the SDE+ 2015, i.e. 12.4 €/kW. ECN and DNV GL observe that the cost of insurance policies in particular is lower, because policies are being concluded with the manufacturer during the guarantee contracts.

For total maintenance costs, including land costs, inflation is assumed to be 2% per year.

Other costs

This year, ECN and DNV GL took a closer look at the costs of participation. The intention is that the code of conduct by NWEA (the Dutch wind energy association), which incorporates a reference amount of 0.4-0.5 €ct/kWh, will make participation costs generic. However, ECN and DNV GL have been instructed by the Ministry not to include these costs in the base rate.

Additional costs of wind projects, such as non-statutory levies to local government and costs resulting from the preparation process (including financing costs and costs resulting from legal proceedings) have also not been included in the calculation of production costs by ECN and DNV GL. These additional costs – like incidental benefits such as purchasing discounts on large projects – are not generic in nature and in accordance with the research assignment are therefore not to be considered by ECN and DNV GL as costs (or income) eligible for subsidy. These costs are assumed to be earned back through the financial return on equity.

Income: returns from turbines

The base rate was established by combining the costs referred to above with the energy output of the wind turbines. These returns are largely determined by the wind resources and the power curve of the wind turbine. The energy output has been calculated for all turbines separately with the help of the specific power curve per wind turbine at the annual average wind speeds indicated in Table 23. The model corrects the wind speed from the table (at an altitude of 100 meters) for the actual height of the axis of the specific turbine. In addition, the model only makes calculations for wind turbines which, based on the IEC classification, are actually permitted to be installed for the specific wind speed.

Like last year, ECN and DNV GL have assumed 13% output losses for a 50 MW reference wind farm. These losses are caused, among other things, by wake losses, non-availability, electrical losses, turbine performance, environmental losses and curtailment.

5.1.2 Overview of base rates

The resulting base rates are shown in Table 25 and should be read in conjunction with Figure 1, in which the Dutch municipalities are differentiated by wind speed categories[7]. The map determines which maximum base rate a project in a particular municipality may apply for.

Example: a project in a municipality coloured red may submit an application for the 'onshore wind, ≥ 8.0 m/s' category (for 0.070 €/kWh) at an unlimited number of full load hours. A project in a blue municipality may submit an application for all the base rates shown in Table 25.

Table 25: Base rates for onshore wind

Category	Base rate (€/kWh)	Colour of municipalities which may submit applications (see Figure 1)
Onshore wind, ≥ 8.0 m/s	0.070	Red, orange, green, blue
Onshore wind, ≥ 7.5 and < 8.0 m/s	0.076	Orange, green, blue
Onshore wind, ≥ 7.0 and < 7.5 m/s	0.082	Green, blue
Onshore wind, < 7.0 m/s	0.093	Blue

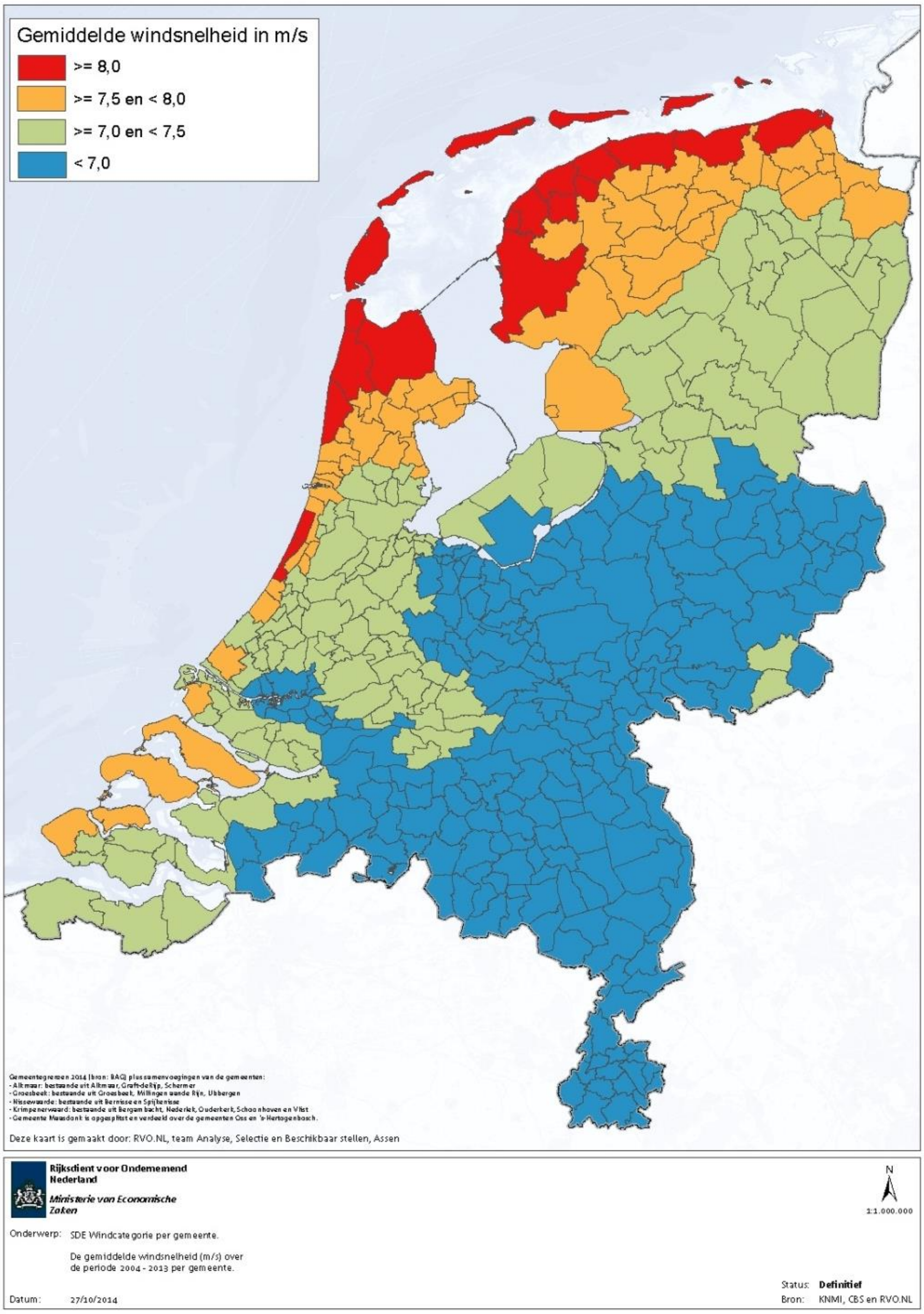
Table 26 shows the base rate and several other subsidy parameters.

Table 26: Overview of subsidy parameters for onshore wind

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.070-0.093
Base price for SDE+ 2016	[€/kWh]	0.030
Provisional correction amount in 2016	[€/kWh]	0.038
Calculation method for correction amount	APX x imbalance factor x profile factor	

[7] *Exception: division of Rotterdam municipality*
Based on large differences in wind speeds for Rotterdam municipality, ECN and DNV GL advise dividing this municipality into two areas by way of exception. In consultation with the Ministry, this division has been made on the basis of municipal district numbers: A) municipal districts 1323, 1318 and 1327; B) other municipal districts in Rotterdam.

Figure 1: Classification of municipalities according to wind speed (average wind speed in m/s) [8]



Source: KNMI, Statistics Netherlands, Netherlands Enterprise Agency (2014).

8 Municipal boundaries 2014 (source: BAG) plus additions of the following municipalities:
- Alkmaar: consisting of Alkmaar, Graft-de Rijp, Schermer
- Groesbeek, consisting of Groesbeek, Millingen aan de Rijn, Ubbergen
- Nissewaard, consisting of Bernisse and Spijkenisse
- Krimpenerwaard: consisting of Bergambacht, Nederlek, Ouderkerk, Schoonhoven and Vlist
- Municipality of Maasdonk is split up and divided among the municipalities of Oss and ‘s-Hertogenbosch

5.2 Onshore wind, one-to-one replacement

At the end of 2014, the Ministry asked ECN and DNV GL to calculate a base rate for one-to-one replacement of wind turbines for the opening of the SDE+ 2015. In the draft advice, this category was also included for the SDE+ 2016. The market consultation revealed that the category, as calculated at that time, is inadequate for the replacement of wind turbines. This is caused, in particular, by the fact that the older the wind turbine is, the more the income from the sale of the old turbine is much reduced (or at least is spread out over a longer period), which means that the base rate is not sufficient in many cases.

To the extent that the category has been included in the SDE+ 2015 for one-to-one replacement in order to prevent surplus profit in the event of the early replacement of wind turbines, ECN and DNV GL recommend limiting the opening of the SDE+: only wind turbines at new locations or replacing wind turbines older than 15 years should qualify for SDE+. This would mean scrapping the 'one-to-one replacement' category.

5.3 Wind on interconnecting water defences

5.3.1 Starting points and calculation method

For the 'wind on interconnecting water defences' category, ECN and DNV GL have assumed that the wind turbines are situated on primary interconnecting water defences or on the water side of *primary sea defences*.

Table 27 shows the technical-economic parameters for 'wind on interconnecting water defences'. These parameters are the same as those for the 'onshore wind' category, except for the investment costs. Explanatory notes may be found in the text below. For an explanation of the other parameters (and the calculation method used), the reader is referred to section 5.1.1 on onshore wind energy.

Table 27: Technical-economic parameters for 'wind on interconnecting water defences'

Parameter	Unit	Advice for 2016	Total amount for reference
Installation size	[MW]	50.0	
Investment costs	[€/kW_e]	1,460	€73.0 million
Fixed O&M costs	[€/kW_e/a]	12.4	€620,000/year
Variable O&M costs	[€/kWh]	0.0139	

Higher CAPEX for 'wind on interconnecting water defences'
Placing a wind turbine on a primary water defence results in the following extra costs compared to the normal 'onshore wind energy' category:

- Foundation costs: the erection of a wind turbine must not cause the dykes to weaken. To ensure this, extra sheet pile walls need to be installed in some cases.
- Civil engineering works: sheet pile walls may also be required for the crane sites and access roads.
- Network connections: potential connection points for wind on interconnecting water defences are often a large distance away. Moreover, additional drilling is often required under the water's surface.

Taking the above additional costs into account, the percentage of additional costs for wind on interconnecting water defences has been set at 50%. Due to the fall in turbine prices (see section 5.1), an adjustment to the total investment costs has also been made for onshore wind. The CAPEX has fallen to 1,460 €/kW.

5.3.2 Overview of base rates

The resulting base rates for wind on interconnecting water defences are shown in Table 28 and should be read in combination with Figure 1, in which the Dutch municipalities are differentiated by wind speed categories. This is because wind differentiation applies to this category (similar to onshore wind). The wind map determines what maximum base rate may be submitted for a project in a particular municipality.

Example: a project in a municipality coloured red may submit an application for the 'wind on interconnecting water defences, ≥ 8.0 m/s' category (for 0.075 €/kWh) at an unlimited number of full load hours. A project in a blue municipality may submit an application for all the base rates shown in Table 28.

Table 28: Base rates for 'wind on connecting water defences'

Category	Base rate [€/kWh]	Colour of municipalities permitted to submit applications (see Figure 1)
'Wind on interconnecting water defences,' ≥ 8.0 m/s	0.075	Red, orange, green, blue
'Wind on interconnecting water defences,' ≥ 7.5 and < 8.0 m/s	0.082	Orange, green, blue
'Wind on interconnecting water defences,' ≥ 7.0 and < 7.5 m/s	0.087	Green, blue
'Wind on interconnecting water defences,' < 7.0 m/s	0.099	Blue

Table 29 shows the base rate and several other subsidy parameters.

Table 29: Overview of subsidy parameters for 'wind on connecting water defences'

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.075-0.099
Base price for SDE+ 2016	[€/kWh]	0.030
Provisional correction amount in 2016	[€/kWh]	0.038
Calculation method for correction amount	APX x imbalance factor x profile factor	

5.4 Wind on lake, water ≥ 1 km²

5.4.1 Starting points and calculation method

Table 30 shows the technical-economic parameters for wind on lake. These parameters (apart from the fixed O&M costs) differ from the parameters used for onshore wind. An explanation of the differing parameters may be found in the text below. For an explanation of the fixed O&M costs, the reader is referred to section 5.1.1 on onshore wind energy.

Table 30: Technical-economic parameters for wind on lake

Parameter	Unit	Advice for 2016	Total amount for reference
Installation size	[MW]	150.0	
Investment costs	[€/kW_e]	2,540	€381.0 million
Fixed O&M costs	[€/kW_e/a]	12.4	€1,860,000/year
Variable O&M costs	[€/kWh]	0.0209	

For wind on lake, a wind farm size of 150 MW has been assumed. Due to the size of the wind farm, the wake losses are higher than for the 50 MW wind farm. In this category, a total of 17% project losses have been assumed instead of the 13% which applies to the 'onshore wind' category. The wind speed has been set at 8.5 m/s, because it has been assumed that 'wind on lake' projects will be located in water subject to high wind speeds.

The investment costs for 'wind on lake' have been set at 2,540 €/kW on the basis of information received from the market and taking into account the fall in turbine prices which will also work its way through for this category. As in previous years, variable O&M costs of 1.7 €ct/kWh have been assumed for this category. In addition there are the land costs, in accordance with the description in Section 5.1.1.

5.4.2 Overview of base rates

The resulting base rate for 'wind on lake' and several other subsidy parameters is shown in Table 31. As for the other wind energy categories, the full load hours cap has been removed for 'wind on lake'. Wind differentiation does not apply. It is anticipated that 'wind on lake' projects will only be developed in the windier parts of the Netherlands.

Table 31: Overview of subsidy parameters for 'wind on lake'

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.114
Base price for SDE+ 2016	[€/kWh]	0.030
Provisional correction amount in 2016	[€/kWh]	0.038
Calculation method for correction amount	APX x imbalance factor x profile factor	

6

Geothermal findings

This chapter describes the findings for the following categories related to geothermal energy. Discussed in order in the following sections are:

- Geothermal heat at a depth of ≥ 500 metres (6.1)
- Geothermal heat at a depth of ≥ 3500 metres (6.2)
- Geothermal co-generation at a depth of ≥ 500 metres (6.3)

6.1 Geothermal heat at a depth of ≥ 500 metres

This section explains the advice on the geothermal energy category for low-temperature heat in more detail. This makes this category representative of the scope of many geothermal heat projects.

The following characteristics are important here:

- Drilling depth (production well: 500 m - 3500 m) with various tube diameters;
- Reference 5,500 full load hours;
- The reference case is based on an average of various geothermal reference cases and scenarios;
- The cost of a two-year construction period (interest during construction) has been factored into the investment cost.

The parameters for the geothermal energy, low-temperature heat reference cases are shown in Table 32. Based on new information, including the responses obtained during the market consultation, amendments have been made to the investment and O&M costs compared to last year. By means of a small reduction in the investment costs and an increase in the O&M costs (both fixed and variable), the base rate has been adjusted upwards slightly.

In addition, ECN, DNV GL and TNO recommend permitting within this category geothermal projects that wish to make use of existing oil or gas wells. An evaluation has been made to see whether such projects can be operated within this category at an acceptable return in the SDE+ 2016. The calculation is based on financial information from the most concrete projects and takes account, on the one hand, of costs avoided due to the reuse of at least one existing well (minus repair costs) and, on the other hand, the claim that oil and gas wells generally have less favourable locations, and that higher costs thus need to be allocated for the heat transport network. Based on these details, it may be asserted that geothermal projects that make use of existing oil and gas wells can be implemented within the base rate for geothermal heat at a depth of >500 m. It should be noted here that various configurations are conceivable for the use of oil and gas wells for geothermal heat. There is currently still a lack of data and initiatives, but for the time being it appears that the existing initiatives have similar costs to greenfield projects in this category.

Table 32: Technical-economic parameters for geothermal heat at a depth of ≥ 500 metres

Parameter	Unit	Advice for 2016	Total amount for reference
Thermal output capacity	[MW]	12	
Full load hours heat supply	[h/a]	5,500	
Investment costs	[€/kW_{th_output}]	1,518	€18.2 million
Fixed O&M costs	[€/$kW_{th\_output/a}$]	62	€744,000/year
Variable O&M costs	[€/GJ_{output}]	2.2	

Table 33 shows the base rate and several other subsidy parameters.

Table 33: Overview of subsidy parameters for geothermal heat at a depth of ≥ 500 metres

Parameter	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.056
Base price for SDE+ 2016	[€/kWh]	0.014
Provisional correction amount in 2016	[€/kWh]	0.017
Calculation method for correction amount	TTF x 70%	

6.2 Geothermal heat at a depth of ≥ 3500 metres

This section explains the advice for the 'high-temperature geothermal heat' category in more detail. This category is focused particularly on higher temperature applications for industrial processes. It is characterised by the greater drilling depth of the production well.

The following characteristics are important here:

- Drilling depth (production well at a depth of ≥ 3500 m) with various diameters;
- Reference: 5,500 full load hours;
- The reference case is based on an average of various geothermal reference cases and scenarios;
- The cost of a two-year construction period (interest during construction) has been factored into the investment cost.

Table 34 shows the technical-economic parameters for the reference case for this category, with a reference drilling depth of 3,700 metres. As in the 'geothermal heat at a depth of ≥ 500 metres' category, for the ≥ 3500 metres category the cost modelling has been adjusted according to the latest insights from the market. Lower investment costs but higher O&M costs (both fixed and variable) have been assumed than in the draft advice. For this category, too, the effect of the increase in the O&M costs is greater than the impact of reducing the investment costs, which means the base rate are higher on balance. On the Ministry's instructions, the number of full load hours has been kept the same at 7,000 hours/year. See Table 34 for the technical-economic parameters of the reference case used for geothermal heat at a depth of > 3500 metres and Table 35 for other subsidy parameters.

Table 34: Technical-economic parameters for geothermal heat at a depth of ≥ 3500 metres

Parameter	Unit	Advice for 2016	Total amount for reference
Thermal output capacity	[MW]	15	
Full load hours heat supply	[h/a]	7,000	
Investment costs	[€/kW_{th_output}]	2,234	€33.5 million
Fixed O&M costs	[€/kW_{th_output}/a]	90	€1,350,000/year
Variable O&M costs	[€/GJ_{output}]	1.8	

Table 35 shows the base rate and several other subsidy parameters.

Table 35: Overview of subsidy parameters for geothermal heat at a depth of ≥ 3500 metres

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.062
Base price for SDE+ 2016	[€/kWh]	0.014
Provisional correction amount in 2016	[€/kWh]	0.017
Calculation method for correction amount	TTF x 70%	

6.3 Geothermal co-generation at a depth of ≥ 500 metres

In the SDE+ 2015, the 'geothermal CHP' category applies to geothermal projects which produce a significant proportion of electricity alongside heat. In the research assignment, ECN, DNV GL and TNO were asked to advise on the opening of this category in the SDE+ 2016.

ECN, DNV GL and TNO advise opening the 'geothermal, co-generation' category in the SDE+ 2016 scheme. During the market consultation, it was discovered that there are several initiatives wanting to make use of the opportunity to sell geothermal energy as electricity.

ECN, DNV GL and TNO advise opening the 'geothermal, co-generation' category in the SDE+ 2016 scheme

These are not projects in which electricity generation is the primary goal, but projects focused on a heat demand that will additionally generate electricity. The concrete initiatives proposed during the market consultation relate to geothermal projects focused on selling heat to local district heating grids, and that want to start generating electricity during the off-peak hours for heat demand. The latter group is explained in more detail below.

The quantity of geothermal energy which can be used depends very much on the flow rate and the difference in temperature between the water piped to homes, buildings or greenhouses and the discharge water. Geothermal projects in the greenhouse horticulture sector make relatively good use of the geothermal potential of a doublet thanks to the significant cooling (the return temperature is generally 35°C).

There is a greater range in the return temperatures for district heating projects and they are also partly dependent on the supply temperature. Modern grids work with a supply temperature of 70°C and a return temperature of 40°C, for example. However, there are also district heating grids aimed at heating existing homes (rather than supplying hot water), which generally involves a supply temperature of 90°C and a return temperature of 70°C. This means there are also various heat grids which have this temperature regime as standard. However, it is not always possible to achieve further cooling, because the demand for heating at this lower temperature is not present everywhere.

Due to the higher return temperature, therefore, the potential capacity of the geothermal source is not utilised to optimum effect. Where a source with a higher capacity is used, more energy is generated for an equal number of full load hours, at broadly similar project costs, which means these projects can be carried out at a lower cost per kWh.

These latter higher-temperature district heating projects are now considering making use of a third geothermal category for CHP, with the market for these unprofitable projects being keen to claim the higher base rate for geothermal CHP. A further aim is to make better use of the potential of the geothermal source by generating electricity in the 'off-peak hours' for heating demand.

If the SDE+ 'geothermal, co-generation' category is scrapped, these projects will fall back on the 'geothermal heat' category. The base rate for 'geothermal, heat at a depth of >500m' will not be sufficient to cover the large financial gap for geothermal heat projects with the heat demand as described above. ECN, DNV GL and TNO therefore advise opening the 'geothermal, co-generation' category for the SDE+ scheme in 2016. The reference case for 'geothermal, co-generation' has been adjusted based on newly obtained information from market parties.

The technical-economic parameters associated with this SDE+ category are shown in Table 36. The input capacity stated in this table refers to the usable capacity of the geothermal project in question. This is limited by the maximum cooling which is possible within the project; it is therefore not the maximum capacity which can be produced by the geothermal source. In practical terms, this means that, in this case, the project cannot simultaneously utilise the maximum capacity for heat and the maximum capacity for electricity. Table 37 also shows other subsidy parameters.

Table 36: Technical-economic parameters for geothermal, co-generation

Parameter	Unit	Advice 2016	Total amount for reference
Input capacity	[MW_{th_input}]	11	
Electrical capacity	[MW_e]	1.1	
Thermal output capacity	[MW_{th_output}]	11	
Full load hours electrical supply	[h/a]	5,000	
Full load hours heat supply	[h/a]	4,000	
Maximum electrical efficiency	[%]	10%	
Investment costs	[€/kW_{input}]	2,388	€29.6 million
ORC investment costs	[€/kW_e]	3,000	
Fixed O&M costs	[€/kW_{input}]	100	€1,100,000/year

Table 37: Overview of subsidy parameters for geothermal, co-generation

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.112
Base price for SDE+ 2016	[€/kWh]	0.017
CHP ratio	[H:E]	8.00
Combined number of full load hours	[hours/year]	4,091
Provisional correction amount in 2016	[€/kWh]	0.020
Calculation method for correction amount	TTF x 70%	

7

Water treatment findings

This chapter describes the findings for the following categories related to water treatment (WWTP):

- Waste water treatment plants, thermophilic digestion of secondary sludge (7.1)
- WWTP - thermal pressure hydrolysis (7.2)
- WWTP – renewable gas (7.3).

7.1 Waste water treatment plants, centralised thermophilic digestion of secondary sludge

Additional biogas production causes increased breakdown of sludge, resulting in lower sludge processing costs.

For this category, a base rate is calculated for thermophilic digestion installations in which secondary sludge, obtained from multiple waste water treatment plants, is centrally processed and the biogas converted into heat and electricity by means of a CHP installation. The advised base rate is based on the same technical-economic parameter values as the advice for 2015. The case has been calculated on the basis of a sludge processing price of 64 €/tonne, which is money saved due to useful application in the form of digestion. This value has been selected as the lowest price: if even lower sludge processing prices are used for the calculation, the base rate will rise very sharply, while at the same time favourably influencing the entire process in financial terms. This case is based on information provided by water boards. Breaking down secondary sludge from multiple sewage treatment plants using this technology saves on sludge processing costs. This saving is calculated with respect to the reference situation in which all the sludge has to be processed. This is shown as a negative amount for the O&M costs. In addition, the cost of the CHP gas engine has been included in the case.

Table 38: Technical-economic parameters for waste water treatment plants, thermophilic digestion of secondary sludge

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	1.90	
Electrical capacity	[MW_e]	0.70	
Thermal output capacity	[MW_{th_output}]	0.92	
Full load hours electrical supply	[h/a]	8,000	
Full load hours heat supply	[h/a]	4,000	
Maximum electrical efficiency	[%]	37%	
Investment costs	[€/kW_e]	15,000	€10.5 million
Fixed O&M costs	[€/kW_e]	-1,140	-€798,000/year

Table 39 shows the base rate and several other subsidy parameters.

Table 39: Overview of subsidy parameters for waste water treatment plants, thermophilic digestion of secondary sludge

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.060
Base price for SDE+ 2016	[€/kWh]	0.029
Heat/power ratio	H:E	0.66
Combined number of full load hours	hours/year	5,729
Provisional correction amount in 2016	[€/kWh]	0.032
Calculation method for correction amount	(APX + TTF x 70% x CHP)/(1 + CHP)	

7.2 WWTP - thermal pressure hydrolysis

This category is unchanged compared to 2014 and 2015. Biogas production from water treatment plants can be increased by adding a thermal pressure hydrolysis installation to an existing purification plant. It is assumed that the existing purification plant already has a CHP gas engine with sufficient capacity.

In water purification plants, purification sludge is digested, with the gas produced in most cases being used to generate electricity using a CHP gas engine. In this way, part of the water purification plant's own energy consumption is covered. A new development in water purification plants is the addition of an installation for thermal pressure hydrolysis to the digestion installation. As a result, a higher gas yield per tonne of sludge is achieved. Upstream thermal pressure hydrolysis also serves to increase the sludge processing capacity of the existing installation. An additional benefit is that the sludge digestate, produced by the digestion of sludge pre-treated with thermal high-pressure hydrolysis, can be further dehydrated, thus reducing the cost of transportation. The reference plant only includes the investment cost for the thermal pressure hydrolysis stage. The costs of dehydration and modification of the existing digestion tank are assumed to be compensated by the lower transportation cost for sludge removal.

The additional gas yield arising from an upstream thermal pressure hydrolysis stage can be used in various ways:

- Electricity production (more electricity generated for the installation's internal use, making full use of the heat from the CHP plant for thermal pressure hydrolysis.)
- Upgrading biogas to green gas quality.
- Crude biogas supply for external applications.

Hydrolysis has its own heat requirement, which can be met by the CHP plant based on the total gas yield of the digester (about 360 Nm^3/h crude biogas). In the case of crude biogas or green gas outputs, more gas is needed to heat the hydrolysis than is supplied by the additional yield from the hydrolysis. Therefore, ECN and DNV KEMA conclude that a CHP option will generally be useful here, with a CHP plant of about 720 kW_e supplying the required heat. In this configuration, all the heat is used for the internal process and only renewable electricity remains as a supplied product eligible for an SDE+ allowance.

This configuration will probably apply to the majority of waste water treatment plants because external heat is not usually available for sewage treatment plants. For situations in which this is the case, a new 'WWTP green gas – thermal pressure hydrolysis' category is recommended.

Table 40: Technical-economic parameters for WWTP - thermal pressure hydrolysis

Parameter	Unit	Advice for 2016	Total amount for reference
Sludge throughput	[tonnes of dry matter/year]	16,000	
Full load hours	[hours/year]	8,000	
CHP capacity (net)	[kW_e]	723	
Total investment	[€/kW_e]	6,100	€4.4 million
Total variable costs	[€/kW_e]	800	€578,000/year

Table 41 shows the base rate and several other subsidy parameters.

Table 41: Overview of subsidy parameters for WWTP - thermal pressure hydrolysis

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.093
Base price for SDE+ 2016	[€/kWh]	0.039
Provisional correction amount in 2016	[€/kWh]	0.042
Calculation method for correction amount	APX	

7.3 WWTP – renewable gas

The 'renewable gas from waste water treatment plant digestion' category has undergone a change compared to last year. The base rate has been calculated for a larger digestion unit, based on data from the Netherlands foundation for applied water research (STOWA, 2011). In view of the limited application of biogas from waste water treatment plants for renewable gas and the large-scale application of CHP in waste water treatment plants (Statistics Netherlands, 2013), plus the heat required for thermal pressure hydrolysis and thermophilic digestion, producing renewable gas rather than using the biogas in a CHP plant would appear to make little sense from the point of view of the efficiency of the SDE+ scheme. In addition, there is a tendency to process sewage treatment sludge at central locations by means of digestion, and for this reason, too, a base rate based on a large plant is realistic. The new base rate is marginally lower than the advised base rate for the previous year.

Table 42: Technical-economic parameters for WWTP – renewable gas

Parameter	Unit	Advice for 2016	Total amount for reference
Reference size	[Nm^3/h green gas]	164.2	
Full load hours	[h/a]	8,000	
Internal heat requirement	[%]	25%	
Internal electricity requirement	[kWh/Nm^3 crude biogas (net)]	0.15	
Electricity rate	[€/kWh]	0.10	
Investment costs	[€/Nm^3/hour crude biogas (gross)]	4,896	€1.5 million
Fixed O&M costs	[€/Nm^3/hour crude biogas (gross)]	504	€158,000/year
Energy content of substrate	[GJ/tonne]	22.0	
Efficiency of gas cleaning	[%]	99.9%	

Table 43 shows the base rate and several other subsidy parameters.

Table 43: Overview of subsidy parameters for WWTP (renewable gas)

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.032
Base price for SDE+ 2016	[€/kWh]	0.020
Provisional correction amount in 2016	[€/kWh]	0.022
Calculation method for correction amount	TTF	

8

Findings for incineration and gasification of biomass

This chapter describes the findings for the categories related to the incineration and gasification of biomass. Ahead of the findings for the different categories, Section 8.1 provides a summary of the biomass prices used. After that, the following categories are discussed in successive sections:

- Prices used for biomass incineration and gasification (8.1).
- Biomass gasification (≥95% biogenic) (8.2).
- Existing direct and indirect co-firing capacity (8.3).
- New capacity for direct co-firing (8.4)
- Boiler fired by solid or liquid biomass 0.5-5 MWth (8.5).
- Boiler fired by solid or liquid biomass ≥5 MWth (8.6).
- Boiler fired by liquid biomass (8.7).
- Heat, wood pellets (8.8).
- Thermal conversion of biomass, > 50 MWth, input (8.9).
- Thermal conversion of biomass, ≤ 50 MW_{th_input} (8.10).

8.1 Prices used for biomass incineration and gasification

Biomass as a fuel is available in different qualities. In this report, a number of reference fuels have been used. For solid biomass, the reference fuel used is pruning and thinning wood and wood pellets. For liquid biomass, the reference fuel used is animal fat.

Table 44 shows a summary of these different references for biomass as a fuel. More detailed explanation of the elements in the table is provided in the following subsections.

Table 44: Biomass prices used for plants applying for SDE+ in 2016 (excluding fuel surcharge)

Biomass for incineration and gasification	Energy content	Supply price to the installation	Reference price
	[GJ/tonne]	[€/tonne]	[€/GJ]
Solid biomass			
Pruning and thinning wood	9	49	5.4
B-grade wood	13	28	2.2
Wood pellets	17	145	9.4
Liquid biomass			
Animal fat	39	600	15.4

8.1.1 Pruning and thinning wood

The reference fuel for new installations for thermal conversion of solid biomass and for boilers fired by solid biomass has changed slightly compared to the advice for the SDE+ 2015 by incorporating the fuel surcharge directly into the fuel price. The reference fuel is pruning and thinning wood. The biomass consists of fresh wood chips from forests, landscapes and gardens. The energy content of fresh wood is about 7 GJ/tonne. However, a large part of the wood delivered to the installations will originate from stock. To allow for the natural drying processes of wood stocks, the annual average energy content has been taken as 9 GJ/tonne. The reference price is assumed to be 49 €/tonne or 5.4 €/GJ. Particularly due to interactions near the border with Germany and Belgium, it may be impossible to obtain pruning and thinning wood for this price in all parts of the Netherlands. The price in Germany is relatively flat at the moment, but it is higher than in the Netherlands. Additionally, it was found during the consultation that the fuel surcharge of 1 €/tonne from previous years is causing confusion. For this reason, this surcharge has now been incorporated into the fuel price, which means the price for pruning and thinning wood has been set at 49 €/tonne.

- Fuel price for pruning and thinning wood: 49 €/tonne.
- Energy content: 9 GJ/tonne.
- No fuel surcharge.

8.1.2 B-grade wood

The fuel price for B-grade wood is assumed to be 28 €/tonne, with an associated energy content of 13 GJ/tonne. For the 'extended lifespan thermal conversion of biomass' category, it is assumed that the decision on the subsidy is known in time, so that the existing fuel contract portfolio can be extended. The current operators have sufficient experience to secure long-term fuel deliveries, so that no fuel price risk surcharge, as allocated to some categories of the SDE+ scheme involving new build projects, needs to be applied in this category.

- Fuel price for B-grade wood: 28 €/tonne.
- Energy content: 13 GJ/tonne.
- No fuel surcharge.

Currency risks are included in the risks of long-term contracting.

8.1.3 Wood pellets

For the 'direct/indirect co-firing' and 'pellet-fired boilers' categories, the biomass fuel is assumed to be clean, white wood pellets with a heating value of 17.0 MJ/kg, in accordance with the trading definition. The cost of the biomass fuel is assumed to be 160 €/tonne (delivered at plant gate). This price is based on input obtained from the market and public sources such as the Argus-index. The price is made up of: 145 €/tonne for delivery to the plant (135 €/tonne current price CIF ARA and 10 €/tonne for the logistical costs of transport from port to plant) and 15 €/tonne risk surcharge for long-term contracting (including currency risk). In this price, a risk premium has been taken into account because this price is set for the eight-year subsidy period and only corrected for inflation, not for any structural price rises. Based on the information received during the market consultation, it was found that the prices for smaller-scale batches of pellets fall within the uncertainty margin of the prices used here.

The choice of biomass fuel and the corresponding price level can also be influenced by the sustainability criteria for biomass in direct co-firing. Earlier this year, government, industry and NGOs reached an agreement about these sustainability criteria. Work is currently under way to firm up a number of essential points from the agreements. As a result, it is unclear how any costs for the associated certification relate to other uncertainties in the assumptions regarding the use of biomass for co-firing.

- Fuel price of wood pellets (including transhipment and logistics): 145 €/tonne.
- Energy content: 17 GJ/tonne.
- Fuel surcharge: 15 €/tonne.

8.1.4 Liquid biomass

After reaching a peak in 2011 and 2012, the prices of vegetable oil and animal fats are now displaying a downward trend. The most recent data appear to show this fall continuing; however, based on the five-year average it is small. For 2016, as for last year, an average price for liquid biomass of 600 €/tonne is assumed at a heating value of 39 GJ/tonne. The prices of animal fats track the prices of vegetable oils. Moreover, there is a well-developed international market for vegetable oils. By trading on the international market for vegetable oils, the risks of rising prices for animal fats can be successfully hedged.

- Fuel price for animal fat: 600 €/tonne.
- Energy content: 39 GJ/tonne.
- No fuel surcharge.

8.2 Biomass gasification (≥95% biogenic)

A bio-SNG installation for green gas production by means of gasification consists of three components: gasification, gas cleaning and gas upgrading. In a gasification installation, solid biomass is converted into a gaseous fuel known as syngas. In the gas cleaning section, impurities are removed from the gas. In the final step, the gas is upgraded to natural gas quality (bio-SNG) after which the green gas can be fed into the natural gas grid.

The reference installation has a capacity of approximately 20 MW_{th} or a production capacity of approximately 1,580 Nm^3 of green gas/hour. The energy efficiency of gasification into bio-SNG is 70%. Although the installation can fulfil its own internal heat requirement, the purchase of electricity for internal use has been included in the calculation of the base rate. Combining a wood-gasifier and a gas upgrading installation results in a complex production installation. Therefore, 7,500 full load hours per year have been assumed. Table 45 provides the technical-economic parameters.

Table 45: Technical-economic parameters for gasification of biomass (≥95% biogenic)

Parameter	Unit	Advice for 2016	Total amount for reference
Reference size	[Nm^3/h]	1,578	
Full load hours	[h/a]	7,500	
Internal electricity requirement	[kWh/Nm^3]	0.45	
Electricity rate	[€/kWh]	0.10	
Investment costs	[€ per Nm^3/h]	43,200	€68.3 million
Fixed O&M costs	[€/a per Nm^3/h]	2,160	€3.4 million/year
Energy content of substrate	[GJ/tonne]	9	
Feedstock costs	[€/tonne]	49	
Efficiency of gas cleaning	[%]	99.9%	

Table 46 shows the base rate. In addition, this table also shows the base price, the contract costs and the correction amount.

Table 46: Overview of subsidy parameters for biomass gasification (≥95% biogenic)

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.151
Base price for SDE+ 2016	[€/kWh]	0.020
Provisional correction amount in 2016	[€/kWh]	0.022
Calculation method for correction amount	TTF	

8.3 Existing capacity for direct and indirect co-firing of biomass

8.3.1 General assumptions

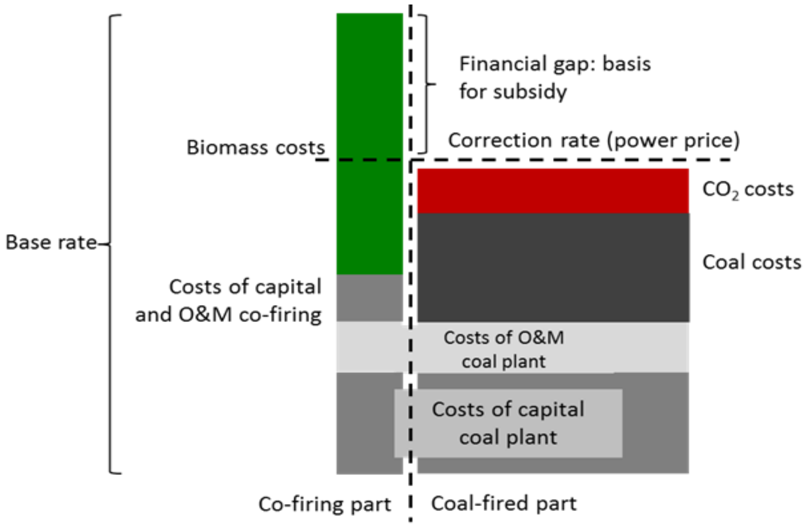
Part of the Netherlands' electricity and heat production comes from coal-fired power plants. Alongside coal, these power plants can also use biomass as a fuel. There are two ways of doing this:

- By direct replacement of coal by biomass, which is put into the boiler as solid fuel. This is called *direct* co-firing.
- By using biomass after a thermal pre-treatment, for example gasification. In this case, the biomass is used via an intermediate product. This is called *indirect* co-firing.

For all categories of direct co-firing, the calculations are based on clean white wood pellets. For indirect co-firing, the reference fuel is B-grade wood. The biomass prices used are explained in Sections 8.1.3 (wood pellets) and 8.1.2 (B-grade wood), respectively.

Delineation of direct/indirect co-firing in coal-fired power plant
In order to calculate the base rate for the use of biomass, the costs of the coal-fired power plant (capital costs and O&M) are allocated proportionately to the share of biomass used. Theoretically speaking, the calculations are based on a virtual biomass power plant the size of which is represented by this share. An illustration of this method is shown in Figure 2. Efficiency losses of the power plant as a whole caused by the use of biomass are also allocated to the biomass proportion. For example, if the yield of the plant as a whole decreases by half a percent with 25% direct co-firing, in the calculations an output decrease of 2% is allocated to the co-firing proportion.

Figure 2: Illustration of the SDE method for biomass co-firing in a coal-fired power plant. Costs in €/kWh$_e$. Stylised figure; the sizes of the cost bars do not correspond exactly to the data in this report.



Capital costs
When calculating the capital costs of the coal-fired power plant, account is taken of the difference between the economic life of the power plant and the duration of the SDE+ allowance for the use of biomass (eight years). The capital costs and operational costs of the coal-fired power plant are allocated proportionately to the part of the power plant that uses biomass. Given an economic lifetime of 30 years, the specific capital costs (€/kW$_e$) of the coal-fired power plant are included in the calculations with a factor of 8/30. For specific investments required to enable the use of biomass, an economic lifetime of eight years is assumed.

Heat supply
In the MEP scheme (Environmental Quality of Electricity Production), the production of heat from using biomass in coal-fired power plants was not subsidised separately. The subsidy was based on the part of the electricity production that would be produced from biomass if there would have been no heat production.

In this SDE+ 2016 advice, the starting point is that the core of this approach will be maintained: there will not be a separate payment for heat; instead the basis for the subsidy will remain the same as the electricity production from biomass that would be achieved without heat transfer.

8.3.2 Description of the reference installation

The text below describes the reference power plants for the 'existing capacity for direct or indirect co-firing' category and specifies the parameters used.

Coal-fired power plant built in the 1990s with existing capacity for direct co-firing of biomass
The reference used for this category is a supercritical 600-650 MW$_e$ coal-fired power station built in the 1990s with a net efficiency of 41%, fitted with FGD, DeNOx and a fine

particles removal system. The production time of electricity generated is assumed to be 6,000 full load hours a year.

It is assumed that the efficiency when burning biomass is 2% lower than when burning coal. Given the fact that the co-firing installation is already present, only limited replacement investments are assumed here.

For the performance of co-firing activities, a proportionate part of the capital and maintenance costs of the coal-fired power plant is allocated to the co-firing activities. The following principles are applied:

- The total investment costs of the coal-fired power plant built in the 1990s are set at 1,100 €/kW_e. Over the duration of the scheme (eight years), and taking the economic life of the coal-fired power station (30 years) into account, a percentage of this price, equal to the co-firing percentage (based on energy,) is factored into the base rate.
- The replacement investment needed to enable the existing co-firing installation to operate for another eight years is estimated at 30 €/kW_e (only calculated over the number of kW_e of co-firing).
- The O&M costs of the coal-fired power plant are 30 €/kW_e, using the same calculation method as for the investment costs.
- The additional O&M costs resulting from biomass co-firing amount to 3 €/MWh_e (only calculated for the kilowatt hours generated using biomass).

Coal-fired power plant built in the 1990s with existing capacity for indirect co-firing of biomass

The reference used for this category is a supercritical coal-fired power station built in the 1990s with a net efficiency of 41%, fitted with FGD, DeNOx and a fine particles removal system. Adjacent to the plant is a biomass gasifier supplying product gas which is used in the coal-fired power plant for indirect co-firing. 5,000 full load hours are assumed for the biomass gasifier.

A thermal efficiency of 95% is assumed for the biomass gasifier. It is assumed that the efficiency when burning product gas is 1% lower than when burning coal.

For the indirect co-firing of biomass, a proportionate part of the capital and maintenance costs of the coal-fired power plant is allocated to the co-firing activities. The following principles are applied:

- The total investment costs of the coal-fired power plant built in the 1990s are set at 1,100 €/kW_e. Over the duration of the scheme (8 years), and taking into account the economic life of the coal-fired power station (30 years), a percentage of this price, equal to the co-firing percentage (based on energy), is factored into the base rate.
- The cost of replacement investments needed to enable the biomass gasifier to operate for another eight years has been set at 75 €/kW_e (only calculated over the number of kW_e of co-firing).
- The O&M costs of the coal-fired power plant are 30 €/kW_e, using the same calculation method as for the investment costs.
- The additional fixed O&M costs for the biomass gasifier amount to €190/kW_e (only calculated over the number of kW_e co-firing). This also includes additional costs for removing all metal from the biomass.

- In addition, there are variable O&M costs for the gasifier amounting to 7.5 €/MWh$_e$ (only calculated for the kilowatt hours generated using biomass).

Table 47 shows the technical-economic parameters for the two reference installations.

Table 47: Technical-economic parameters for existing biomass co-firing capacity

Parameters for reference installations	Unit	Direct co-firing value	Indirect co-firing value
Net electrical capacity of the power plant	[MW$_e$]	600-650	600-650
Direct/indirect co-firing percentage	[e/e %]	27	5
Thermal full load efficiency of coal	[%]	41	41
Full load hours of electricity production	[h/a]	6,000	5,000
Efficiency of biomass gasifier	[%]	-	95
Efficiency of biomass portion of plant	[%]	39*	38*/**
Cost of biomass	[€/tonne]	160	28
Duration of incentive scheme	[a]	8	8
Specific investment for use of biomass (extension of economic lifetime)	[€/kW$_e$]	30	75
Investment costs for coal-fired power plant	[€/kW$_e$]	1,100	1,100
Economic lifetime of coal-fired power plant	[a]	30	30
O&M costs for coal-fired power plant	[€/kW$_e$]	30	30
Additional O&M costs for direct co-firing (biomass MWh)	[€/MWh$_e$]	3	-
Additional fixed O&M costs for biomass gasifier	[€/kW$_e$]	-	190
Additional variable O&M costs for biomass gasifier	[€/MWh$_e$]	-	7.5

*: Output loss of the power plant as a whole resulting from indirect or direct co-firing of biomass is allocated entirely to the biomass portion.
**: Including the efficiency of the gasifier.

Table 48 shows the base rate. This is based on an average of direct and indirect co-firing weighted according to capacity. In addition, this table also shows the base price, the base price premium, the correction amount and the method used to calculate the correction amount.

Table 48: Overview of subsidy parameters for existing direct and indirect co-firing capacity

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.107
Base price for SDE+ 2016	[€/kWh]	0.039
Weighted number of full load hours	[hours/year]	5,839
Provisional correction rate in 2016	[€/kWh]	0.042
Calculation method for correction rate	APX	

8.4 New capacity for direct co-firing of biomass

The text below describes the reference power plant for the 'new capacity for direct co-firing' category and states the parameters used. An overview of these parameters is presented in Table 49. The general principles for direct and indirect co-firing of biomass from Section 8.3.1 also apply to new capacity for direct co-firing.

Coal-fired power plant built in the 2010s with new capacity for direct co-firing of biomass

The reference for this category is a supercritical coal-fired power station in the range 700 to 1100 MW_e with a net full load efficiency of 46%, fitted with FGD, DeNOx and fine particles removal system. The production time of electricity generated is assumed to be 7,000 full load hours.

It is assumed that the efficiency when burning biomass is 2% lower than when burning coal. For the creation of the new co-firing plant, an investment amount of 450 €/kW_e is assumed (only calculated over the number of kW_e co-firing).

For the performance of co-firing activities, a proportionate part of the capital and maintenance costs of the coal-fired power plant are allocated to the co-firing activities. The following principles are applied:

- The total investment costs of the coal-fired power plant are 2000 €/kW_e. Over the duration of the scheme (8 years), and taking the economic lifetime of the coal-fired power station (30 years) into account, a percentage of the costs, equal to the co-firing percentage (based on energy), is factored into the base rate.
- The O&M costs of the coal-fired power plant are 30 €/kW_e. This will also be included in the calculation in proportion to the co-firing capacity.
- The extra O&M costs resulting from biomass co-firing amount to 3 €/MWh_e (only calculated for the kilowatt hours generated using biomass).

The economic lifetime of the biomass co-firing installation is equal to the duration of the scheme (starting point for SDE system).

Table 49: Technical-economic parameters for new capacity for direct biomass co-firing in power plants built in the 2010s

Parameter	Unit	Advice 2016
Net electrical capacity of the power plant	[MW_e]	700-1,100
Thermal full load efficiency of coal	[%]	46%
Direct co-firing percentage	[e/e %]	20%
Full load hours of electricity production	[h/a]	7,000
Thermal full load efficiency	[%]	44%
Cost of biomass	[€/tonne]	160
Duration of incentive scheme	[a]	8
Specific investment for biomass direct co-firing	[€/kW_e]	450
Investment costs for coal-fired power plant	[€/kW_e]	2,000
Economic lifetime of coal-fired power plant	[a]	30
O&M costs of coal-fired power plant	[€/kW_e]	30
Additional O&M costs for biomass co-firing	[€/MWh_e]	3.0

*: The efficiency loss of the power plant as a whole resulting from biomass direct co-firing is entirely allocated to the biomass portion.

Table 50 shows the base rate and several other subsidy parameters.

Table 50: Overview of subsidy parameters for new direct co-firing capacity

	Unit	SDE+ 2016 advice
Base rate SDE+ 2016	[€/kWh]	0.114
Base price SDE+ 2016	[€/kWh]	0.039
Provisional correction rate 2016	[€/kWh]	0.042
Calculation method for correction amount	APX	

8.5 Boiler fired by solid or liquid biomass 0.5-5MW$_{th}$

The reference installation for this category is a hot water boiler with a combustion grate, using wood from cutting and pruning as the reference fuel. Supplementary to this reference installation, allowance has been made for investments in flue gas cleaning equipment required by the Activities Decree. For example, for installations below 1 MW$_{th}$, the cost of a dust filter has been included. Installations larger than 1 MW$_{th}$ will also require a $DeNO_x$ installation. Due to the economies of scale enjoyed by these installations compared to the reference case, we regard the specific investment costs for these installations to be the same as those for the reference case. The number of full load hours is assumed to be 4,000 hours per year. The investment costs have been re-assessed this year, resulting in an increase to €460/kW$_{th,output}$.

Table 51 shows the technical-economic parameters for boilers fired by solid biomass.

Table 51: Boilers fired by solid biomass, 0,5-5 MW$_{th}$

Parameter	Unit	Advice for 2016	Total amount for reference
Thermal output capacity	[MW$_{th_output}$]	0.75	
Full load hours heat supply	[h/a]	4,000	
Investment costs	[€/kW$_{th_output}$]	460	€0.3 million
Fixed O&M costs	[€/kW$_{th_output}$]	45	€34,000/year
Energy content of fuel	[GJ/tonne]	9.0	
Fuel price	[€/tonne]	49	

Table 52 shows the base rate and several other subsidy parameters.

Table 52: Overview of subsidy parameters for boiler fired by solid or liquid biomass, 0.5-5 MW$_{th}$

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.052
Base price for SDE+ 2016	[€/kWh]	0.025
Provisional correction amount in 2016	[€/kWh]	0.031
Calculation method for correction amount	(TTF + energy tax)/gas boiler efficiency	

8.6 Boiler fired by solid or liquid biomass ≥5 MW_{th}

The reference installation for this category is a hot water boiler with a combustion grate, using wood from cutting and pruning as reference fuel. Supplementary to this reference installation, allowance has been made for investments required by the Activities Decree. The flue gas cleaning for this category calls for higher investments than for the 0.5 - 5 MW_{th} category. We have assumed that NO_x emissions can be reduced sufficiently with the use of an SNCR system. In addition, allowance has been made for higher investments than for the reference installation in relation to supplementary biomass storage. This balances out the economies of scale compared to the 0.5 - 5 MW_{th} category. The investment costs have been re-assessed this year, resulting in €460/$kW_{th,output}$.

In this category, it is possible to achieve heat supply with a boiler fired by solid biomass to replace a gas-fired CHP. For this reason, the number of full load hours has been set at 7,000 hours per year for this category.

An overview of the technical-economic parameters for boilers fired by solid biomass (≥5 MW) is shown in Table 53.

Table 53: Technical-economic parameters for boilers fired by solid or liquid biomass ≥5 MW_{th}

Parameter	Unit	Advice 2016	Total amount for reference
Thermal output capacity	[MW_{th_output}]	10	
Full load hours heat supply	[h/a]	7,000	
Investment costs	[€/kW_{th_output}]	460	€4.6 million
Fixed O&M costs	[€/kW_{th_output}]	62	€620,000/year
Energy content of fuel	[GJ/tonne]	9.0	
Fuel price	[€/tonne]	49	

Table 54 shows the base rate and several other subsidy parameters.

Table 54: Overview of subsidy parameters for boiler fired by solid or liquid biomass, ≥5 MW_{th}

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.043
Base price for SDE+ 2016	[€/kWh]	0.014
Provisional correction amount in 2016	[€/kWh]	0.017
Calculation method for correction amount	TTF x 70%	

8.7 Boiler fired by liquid biomass

In some cases, gas-fired boilers can be replaced relatively quickly and easily by boilers fired by liquid biomass, for example pyrolysis oil or animal fat. The selected reference fuel is animal fat. Given the relatively small contribution of the investment costs to the base rate and the option for initiators to further reduce these investment costs by installing modified burners in existing boilers, the investment amount has been set at zero in this advice. This makes the calculation representative for the use of liquid biomass in new bio-boilers as well as for the use of liquid biomass in modified, existing boilers. Table 55 shows the parameters for a boiler fired by liquid biomass.

Table 55: Technical-economic parameters for boiler fired by liquid biomass

Parameter	Unit	Advice for 2016	Total amount for reference
Thermal output capacity	[MW_{th_output}]	10	
Full load hours heat supply	[h/a]	7,000	
Investment costs	[€/kW_{th_output}]	0	€0.0 million
Fixed O&M costs	[€/kW_{th_output}]	24	€240,000/year
Energy content of fuel	[GJ/tonne]	39.0	
Fuel price	[€/tonne]	600	
Fuel surcharge	[€/tonne]	0	

Table 56 shows the base rate and several other subsidy parameters.

Table 56: Summary of subsidy parameters for boiler fired by liquid biomass

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.071
Base price for SDE+ 2016	[€/kWh]	0.025
Provisional correction amount in 2016	[€/kWh]	0.031
Calculation method for correction amount	(TTF + energy tax)/gas boiler efficiency	

8.8 Heat, wood pellets > 5 MW_{th}

For this category, the reference installation is a water tube boiler, supplying steam at 35 bar, in which wood pellets are used as reference fuel. The fuel is stored in silos. The consultation revealed that various market parties have a preference for grate boilers rather than powder boilers. A new cost estimate has been made to reflect this fact. The consultation also revealed that there is interest in capacities below 10 MW_{th}. The market consultation generated two analyses, both based on the ETS data for various industrial sectors. The conclusion from these analyses is that at a lower limit of 10 MW_{th} it is possible to achieve approximately 80% of the potential energy production in industry, and at a lower limit of 5 MW_{th} this is approximately 90% of potential energy production. From this perspective, we advise lowering the lower limit to 5 MW_{th}.

It is assumed that the installation can operate autonomously and be controlled remotely. The output of the boiler is 30 MW_{th} and the boiler is assumed to have an efficiency of 90%.

The number of full load hours of heat supply is 7,000 hours per year, which corresponds to the 'boiler fired by solid or liquid biomass > 5 MW_{th}' category. The investment costs for the reference installation amount to 460 €/$kW_{th, output}$ with associated O&M costs of 27.6 €/$kW_{th, output}$. This means the investment costs are the same as for the 'pruning and thinning wood' category. The more expensive steam boiler and steam appendages for the pellet category are compensated by the simpler fuel storage and transport associated with this type of installation. The O&M costs for this category are lower than those for the category based on pruning wood. This is because the storage and transport of fuel can be performed on a smaller scale and more easily, which means fewer staff and replacement parts are needed to operate and maintain the installation.

It has been assumed that the wood pellets are supplied in bulk, which means the fuel price can be set at the same level as that for wood pellets in the direct/indirect co-firing category. The technical-economic parameters are shown in Table 57. At the Ministry's instructions, a subsidy term of 8 years has been assumed for this category.

Table 57: Technical-economic parameters for heat, wood pellets

Parameter	Unit	Advice for 2016	Total amount for reference
Thermal output capacity	[MW_{th_output}]	30	
Full load hours heat supply	[h/a]	7,000	
Investment costs	[€/kW_{th_output}]	460	€13.8 million
Fixed O&M costs	[€/kW_{th_output}]	27.6	€828,000/year
Energy content of fuel	[GJ/tonne]	17.0	
Fuel price	[€/tonne]	145	
Fuel surcharge	[€/tonne]	15	

Table 58 shows the base rate and several other subsidy parameters.

Table 58: Overview of subsidy parameters for heat, wood pellets

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.057
Base price for SDE+ 2016	[€/kWh]	0.014
Provisional correction amount in 2016	[€/kWh]	0.017
Calculation method for correction amount	TTF x 70%	

8.9 Thermal conversion of biomass, > 50 $MW_{th, input}$

The reference case is a wood-fired installation for supplying electricity and heat with an input capacity of approximately 75.8 MW_{th}. The boiler can supply heat to a district heating grid at a temperature of 100-120°C using low pressure steam extraction by means of a back pressure turbine. The assumption is that the back pressure turbine can supply 50.0 $MW_{th.}$

The reference installation is assumed to be linked to a large existing district heating grid, allowing for optimum utilisation of the heat generated. The number of full hours of heat supply has therefore been taken to be 7,500 hours. At times when there is no need for full load heat supply, the entire installation will operate at partial load. Such an installation will usually be located in an industrial area, close to existing conventional CHP plants and good supply routes for biomass.

The reference installation is based on pruning and thinning wood as fuel. Due to the lower energy content of fresh wood flows, a larger storage and transport system is needed, as well as a larger incineration component for the installation. The flue gas cleaning need not be as extensive as for other fuels, given that fresh wood contains less harmful components than for example B-grade wood. The technical-economic data for these reference plants have been summarised in Table 59.

The minimum capacity of this category has been amended this year, in order to make it equal to the limit for emissions thresholds used in the Activities Decree. Based on current market data, electrical efficiency has increased and the specific investment and O&M costs have been reduced.

ECN and DNV GL advise a minimum electrical output capacity of 15% of the thermal input capacity.

The Ministry of Economic Affairs has also requested that a minimum electrical efficiency be defined on the basis of the capacity determined for this category. ECN and DNV GL advise setting this minimum electrical output capacity at 15% of the thermal input capacity (minimum electrical efficiency 15%).

Table 59: Technical-economic parameters for thermal conversion of biomass, > 50 MW_{th_input}

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	75.8	
Electrical capacity	[MW_e]	16.7	
Thermal output capacity	[MW_{th_output}]	50	
Full load hours electrical supply	[h/a]	7,500	
Full load hours heat supply	[h/a]	7,500	
Maximum electrical efficiency		22%	
Electricity loss in heat supply		-	
Investment costs	[€/kW_{th_input}]	1,650	€125.1 million
Fixed O&M costs	[€/kW_{th_input}]	100	€7.6 million /year
Energy content of fuel	[GJ/tonne]	9.0	
Fuel price	[€/tonne]	49	

Table 60 shows the base rate and several other subsidy parameters.

Table 60: Overview of subsidy parameters for thermal conversion of biomass, > 50 MW_{th_input}

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.077
Base price for SDE+ 2016	[€/kWh]	0.020
CHP ratio	[H:E]	2.99
Combined number of full load hours	[hours/year]	7,500
Provisional correction amount in 2016	[€/kWh]	0.023
Calculation method for correction amount	(APX + TTF x 70% x CHP)/(1 + CHP)	

8.10 Thermal conversion of biomass, ≤ 50 $MW_{th, input}$

Many initiatives up to 50 $MW_{th, input}$ are developed for locally available biomass flows, with local authorities often playing an initiating or facilitating role. The reference installation is based on a boiler with a condensing turbine and a thermal input capacity of 8.7 MW_{th} which is able to supply a maximum of 1.65 MW_e electricity and 5 MW_{th} heat.

The amounts for the investment costs and the O&M costs are based on projects delivered in the past or on information supplied in the past during the consultation in relation to planned projects. Based on this, a reference case has been drawn up which was included in the advice for 2016 and previous years.

The maximum capacity for this category has been amended this year in order to make it equal to the limit for emissions thresholds used in the Activities Decree. The Ministry of Economic Affairs has also requested that a minimum electrical efficiency be defined on the basis of the capacity determined for this category. ECN and DNV GL advise setting this minimum electrical output capacity at 15% of the thermal input capacity (minimum electrical efficiency 15%).

ECN and DNV GL advise a minimum electrical output capacity of 15% of the thermal input capacity.

Table 61: Technical-economic parameters for thermal conversion of biomass, < 50 MW_{th_input}

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	8.7	
Electrical capacity	[MW_e]	1.65	
Thermal output capacity	[MW_{th_output}]	5.0	
Full load hours electrical supply	[h/a]	8,000	
Full load hours heat supply	[h/a]	4,000	
Maximum electrical efficiency		19%	
Electricity loss in heat supply		1/4	
Investment costs	[€/kW_{th_input}]	1,400	€12 million
Fixed O&M costs	[€/kW_{th_input}]	80	€ 0,69 million /year
Variable O&M costs	[€/kWh]	0.006	
Energy content of fuel	[GJ/tonne]	9.0	
Fuel price	[€/tonne]	49	

Table 62 shows the base rate and several other subsidy parameters.

Table 62: Overview of subsidy parameters for thermal conversion of biomass, < 50 MW_{th_input}

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.143
Base price for SDE+ 2016	[€/kWh]	0.021
CHP ratio	[H:E]	2.44
Combined number of full load hours	[hours/year]	4,241
Provisional correction amount in 2016	[€/kWh]	0.024
Calculation method for correction amount	(APX + TTF x 70% x CHP)/(1 + CHP)	

9

Biomass digestion findings

This chapter describes the findings for the categories related to the digestion of biomass. Ahead of the findings for the different categories, section 9.1 provides a summary of the biomass prices used. After that, the following categories are discussed in successive sections:

- Prices used for biomass digestion (9.1).
- All-feedstock digestion (renewable gas) (9.2).
- Co-generation, all-feedstock digestion (9.3).
- Heat, all-feedstock digestion (9.4).
- Digestion and co-digestion of animal manure (renewable gas) (9.5).
- Co-generation, digestion and co-digestion of animal manure (9.6).
- Heat digestion and co-digestion of animal manure (9.7).
- Digestion of more than 95% animal manure (renewable gas) (9.8).
- Co-generation, digestion of more than 95% animal manure (renewable gas) (9.9).
- Heat digestion of more than 95% animal manure (9.10).

Alongside the technical-economic parameters, these sections also give the base rate, base price, correction amount for 2015 and the method used to calculate the correction amount for each category.

9.1 Prices used for biomass digestion

Biomass as a fuel is available in different qualities. In this report, a number of reference fuels have been used. Two references are mentioned for digestion: biomass for all-feedstock digesters and biomass for manure co-digesters. Table 63 shows a summary of these different references for biomass as a fuel. More detailed explanation of the elements in the table is provided in the following sub-sections.

Table 63: Biomass prices used for digestion plants applying for SDE+ in 2016

Biomass for digestion*	Energy content	Price (range)	Reference price
	[GJ/tonne]	[€/tonne]	[€/GJ]
All-feedstock digestion input	3.4	26.7	7.9
Co-digestion input	3.4	35.9	10.7

* The energy content of digestion input is given in GJ_{biogas}/tonne. The reference price for digestion input is given in €/GJ_{biogas}.

9.1.1 Digestion: biomass for all-feedstock digesters

The reference case used for the 'all-feedstock digestion' category is an installation that uses waste flows from the food and beverage industry or from biofuel production. The reference fuel is assumed to consist of waste products from the food and beverage industry, with the price level being determined by the animal feed markets. The reference price was established based on information from LEI regarding the 5-year average trend for animal feeds. The reference price for SDE+ 2016 has been set at 26.7 €/tonne at a biogas production of 3.4 GJ/tonne.

9.1.2 Digestion: biomass for manure co-digesters

Feedstock for manure co-digestion: fertiliser

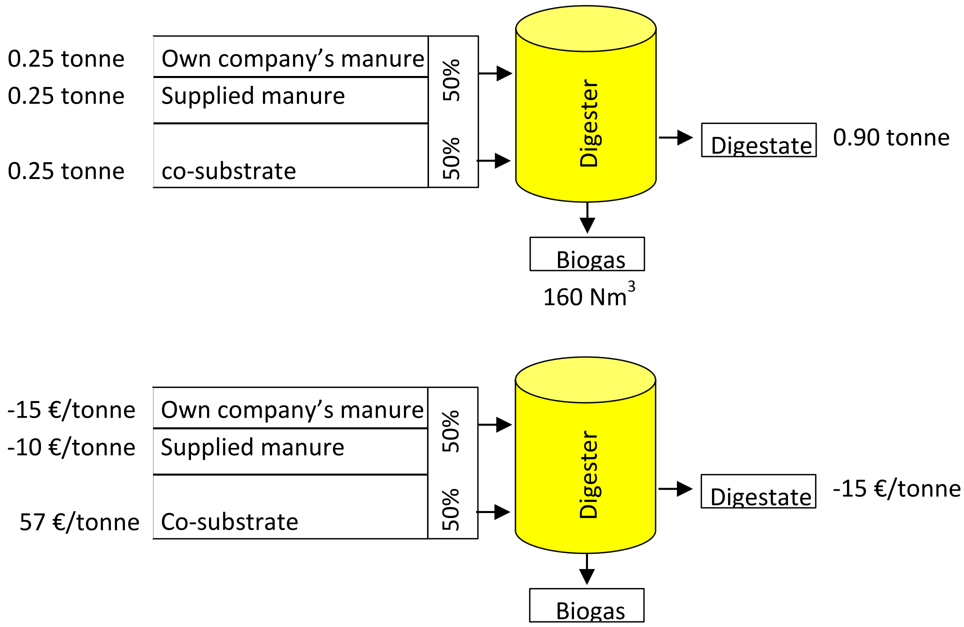
The price of slurry displays regional differences, ranging from 0 to -5 € per tonne in areas with manure shortages up to a maximum of -15 to -20 € per tonne in manure surplus areas. The reference price is assumed to be -15 € per tonne for a firm's own manure. To make allowances for additional transportation costs, the reference price for external supply has been taken to be -10 €/tonne. About 90% of the total input remains as digestate. On average, the removal of digestate costs an additional 15 € per tonne.

Feedstock for manure co-digestion: co-substrate

In 2012, 80 new products that can serve as co-substrates were added to the so-called positive list of co-products. Permitting these co-products has resulted in a better alignment with regulations for foreign digesters. Co-products are subject to limits for the concentrations of heavy metals and organic impurities. However, expanding the list has not succeeded in easing the pressure on the market for co-products.

To prevent the annual fluctuations from having too great an impact on the calculated base rates, the market consultation of 2010 yielded the insight that a long-term average is a more desirable starting point. In order to correct for fluctuations, the average of the last five years has been calculated, based on trade information from LEI (corrected for transport). Figure 3 provides a schematic overview of the assumed feedstock flows in the co-digester.

Figure 3: Flows and prices of digestion inputs and outputs[9]



The reference gas yield of co-substrate is assumed to be 291 Nm^3/tonne. The average price of co-substrate (excluding maize) is 9.4 €/GJ or 57 €/tonne at the start of the project, with a net energy content of 6.1 GJ/tonne. The total assumed feedstock costs, consisting of the purchase of maize, co-substrate and processing costs for manure and digestate, in the current mix amounts to 35.9 €/tonne, or 22 ct/Nm^3 crude biogas, assuming a gas yield from the total input, manure and co-substrate of 3.4 GJ/tonne (excluding a 0.5 €/tonne fuel surcharge). An overview is shown in Table 64.

Table 64: Prices of manure and co-substrate

	Energy content	Price (range)	Reference price
	[GJ/tonne]	[€/tonne]	[€/GJ]
Supply of animal manure	*0.63*	*-10 (-20 to 0)*	*-16*
Removal of animal manure	*0.63*	*-15 (-30 to -5)*	*-24*
Co-substrate	*6.1*	*57.3*	*9.4*
Co-digestion input	3.4	35.9	10.7

9 The calculation methodology is based on the typical method used in the market of expressing the energy content of the manure input and co-substrates in gas yield in Nm^3/tonne or GJ/tonne for a particular energy content of the gas (21 MJ/m^3). In the calculation, the energy content of feedstock is expressed in GJ gas yield per tonne of input. For the sake of completeness: tonnes of input are based on the entire product and not just on the dry matter content.

According to market expectations, new manure co-digesters will immediately result in increasing prices if they attract a higher SDE+ allowance than existing installations. In the tension between existing players and new entrants to the market there is an extra aspect which plays a role among the manure co-digesters, namely that many existing manure co-digesters are achieving lower financial returns than was intended when the installations were built. Finance for new manure co-digesters is hard to obtain.

In the market consultation carried out ahead of this report, ECN and DNV GL received conflicting signals: on the one hand, the 5-year averages of biomass prices have risen, but on the other hand, giving new installations a higher SDE+ allowance than existing installations is regarded as undesirable.

9.2 All-feedstock digestion (renewable gas)

The reference technology for this category is a digester with a production capacity of 950 Nm^3/h crude biogas or 590 Nm^3/h renewable gas. The biogas produced is upgraded to renewable gas. The reference gas purification technology chosen is membrane technology, in view of the fact that this technology has been used for several recent renewable gas projects. This technology works at high pressures in order to achieve the separation between CH_4 and CO_2. For this reason it is assumed that the renewable gas produced can be fed into the local 8-bar grid. With this technology, the CO_2 flow can be further cooled into the by-product liquid CO_2. However, when calculating the base rate, no account has been taken of the additional investment and O&M costs of this step.

The heat required to heat the digester is generated by firing part of the crude biogas in a boiler. The electricity required is obtained from the grid; see Table 65 for the technical-economic parameters of renewable gas production in all-feedstock digesters. It should be noted that the base rates have been calculated on the basis of a stand-alone installation and not a hub connection.

Table 65: Technical-economic parameters for energy from all-feedstock digestion (renewable gas)

Parameter	Unit	Advice for 2016	Total amount for reference
Reference size	[$Nm^3_{gross\ crude\ biogas}$/h]	950	
Full load hours	[h/a]	8,000	
Internal heat requirement	[% biogas]	5%	
Internal electricity requirement (digester)	[kWh/$Nm^3_{gross\ crude\ biogas}$]	0.12	
Internal electricity requirement (gas upgrading)	[kWh/$Nm^3_{net\ crude\ biogas}$]	0.35	
Electricity rate	[€/kWh]	0.10	
Investment costs (digester)	[€ per $Nm^3_{gross\ crude\ biogas}$/h]	3,900	€6 million
Investment costs (gas upgrading)	[€ per $Nm^3_{net\ crude\ biogas}$/h]	2,327	combined
Fixed O&M costs (digester)	[€ per $Nm^3_{gross\ crude\ biogas}$/h]	232	€0.33 million/year
Fixed O&M costs (gas upgrading)	[€ per $Nm^3_{net\ crude\ biogas}$/h]	122	combined
Energy content of substrate	[GJ_{biogas}/tonne]	3.4	
Feedstock costs	[€/tonne]	25	
Efficiency of gas cleaning	[% methane]	99.9%	

Table 66 shows the base rate and several other subsidy parameters.

Table 66: Overview of subsidy parameters for all-feedstock digestion (renewable gas)

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.060
Base rate for SDE+ 2016	[€/kWh]	0.020
Provisional correction amount in 2016	[€/kWh]	0.022
Calculation method for correction amount	TTF	

9.3 Co-generation, all-feedstock digestion

In the 'all-feedstock digestion to electricity and heat' digestion option, an existing industrial installation is modified by integrating a production installation for electricity or heat being into the existing installation. The feedstock is primarily released from the existing installation and the energy from the biogas produced is largely returned to the same existing installation in the form of heat and power.

For the reference installation, a scale of 3 MW_e (8.1 MW_{th_input}) has been assumed.

Table 67 shows the technical-economic parameters for all-feedstock digestion for co-generation (CHP).

Table 67: Technical-economic parameters for energy from co-generation, all-feedstock digestion

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	8.1	
Electrical capacity	[MW_e]	3.0	
Thermal output capacity	[MW_{th_output}]	3.888	
Full load hours electrical supply	[h/a]	8,000	
Full load hours heat supply	[h/a]	4,000	
Maximum electrical efficiency		37%	
Investment costs	[€/kW_{th_input}]	994	€8 million
Fixed O&M costs	[€/kW_{th_input}]	57	€462,000/year
Energy content of fuel	[GJ_{biogas}/tonne]	3.4	
Feedstock costs	[€/tonne]	25	

Table 68 shows the base rate and several other subsidy parameters.

Table 68: Overview of subsidy parameters for co-generation, all-feedstock digestion

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.087
Base price for SDE+ 2016	[€/kWh]	0.029
CHP ratio	[H:E]	0.65
Combined number of full load hours	[hours/year]	5,742
Provisional correction amount in 2016	[€/kWh]	0.032
Calculation method for correction amount	(APX + TTF x 70% x CHP)/(1 + CHP)	

9.4 Heat, all-feedstock digestion

In the 'all-feedstock digestion to heat' digestion option, an existing installation is modifiedby integrating a production installation for heat into the existing installation. The feedstock is primarily released from the existing installation and the energy from the biogas produced is largely returned to the same existing installation in the form of heat.

Table 69 shows the technical-economic parameters for all-feedstock digestion for renewable heat.

Table 69: Technical-economic parameters for energy from heat, all-feedstock digestion

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	8.1	
Full load hours heat supply	[h/a]	7,000	
Internal heat requirement	[%]	5	
Internal electricity requirement	[kWh/GJ_{output}]	5.41	
Electricity rate	[€/kWh]	0.10	
Investment costs	[$€/kW_{th\_output}$]	850	€5.9 million
Fixed O&M costs	[$€/kW_{th\_output}$]	47	€324,000/year
Energy content of fuel	[GJ_{biogas}/tonne]	3.4	
Feedstock costs	[€/tonne]	25	

Table 70 shows the base rate and several other subsidy parameters.

Table 70: Overview of subsidy parameters for heat, all-feedstock digestion

	Unit	Advice 2015
Base rate for SDE+ 2016	[€/kWh]	0.060
Base price for SDE+ 2016	[€/kWh]	0.025
Provisional correction amount in 2016	[€/kWh]	0.031
Calculation method for correction amount	(TTF + energy tax)/gas boiler efficiency	

9.5 Digestion and co-digestion of animal manure (renewable gas)

For the reference installation for animal manure digestion, a production capacity has been assumed of 505 Nm^3/h crude biogas (or 315 Nm^3/h renewable gas). The size of the digester in an installation of this size is comparable to that of a digester in a 1.1 MW_e bio CHP plant. Economies of scale appear to be limited for digesters. The maximum size of a digestion tank is restricted by the fact that the material needs to be able to be homogenised; the diameter of the roof of a digester is also subject to a maximum size. Consequently, for production at a larger scale, several tanks are often placed side by side.

The reference gas purification technology chosen is membrane technology, in view of the fact that this technology has been used for several recent renewable gas projects. This technology works at high pressures in order to achieve the separation between CH_4 and CO_2. For this reason it is assumed that the renewable gas produced can be fed into the local 8-bar grid. The CO_2 flow can be further cooled into the by-product liquid CO_2

using this technology. However, when calculating the base rate, no account has been taken of the additional investment and O&M costs of this step.

The heat required to heat the digester is generated by firing part of the crude biogas in a boiler. The electricity required is obtained from the grid. Table 71 shows the technical-economic parameters for the production of renewable gas. It should be noted that the base rates have been calculated on the basis of a stand-alone installation and not a hub connection.

Table 71: Technical-economic parameters for energy from manure co-digestion (renewable gas)

Parameter	Unit	Advice for 2016	Total amount for reference
Reference size	[$Nm^3_{gross\ crude\ biogas}$/h]	505	
Full load hours	[h/a]	8,000	
Internal heat requirement	[% biogas]	5%	
Internal electricity requirement (digester)	[kWh/$Nm^3_{gross\ crude\ biogas}$]	0.12	
Internal electricity requirement (gas upgrading)	[kWh/$Nm^3_{net\ crude\ biogas}$]	0.35	
Electricity rate	[€/kWh]	0.10	
Investment costs (digester)	[€ per $Nm^3_{gross\ crude\ biogas}$/h]	4,515	€4 million
Investment costs (gas upgrading)	[€ per $Nm^3_{net\ crude\ biogas}$/h]	2,876	combined
Fixed O&M costs (digester)	[€ per $Nm^3_{gross\ crude\ biogas}$/h]	366	€0.26 million/year
Fixed O&M costs (gas upgrading)	[€ per $Nm^3_{net\ crude\ biogas}$/h]	154	combined
Energy content of substrate	[GJ_{biogas}/tonne]	3.4	
Feedstock costs	[€/tonne]	36.4	
Efficiency of gas cleaning	[% methane]	99.9%	

Table 72 shows the base rate and several other subsidy parameters.

Table 72: Overview of subsidy parameters for manure co-digestion (renewable gas)

	Unit	Advice for 2016
Base rate for SDE+ 2016	[€/kWh]	0.080
Base price for SDE+ 2016	[€/kWh]	0.020
Provisional correction amount in 2016	[€/kWh]	0.022
Calculation method for correction amount	TTF	

9.6 Co-generation, digestion and co-digestion of animal manure

For the reference installation, a scale of 1.1 MW_e (3 MW_{th_input}) has been assumed. An installation of this size remains well below the MER limit (MER = Environmental Impact Assessment) and can be supplied with manure by two large farms. In the first year, there will be additional costs for starting up the installation. These additional costs are included in the investment cost and result in a total investment cost of 1,145 €/kW_{th_input}.

Calculations for the SDE+ base rates are based on an electrical efficiency for converting the biogas into net electricity supply of 37%.

Table 73 shows the technical-economic parameters for all-feedstock digestion for co-generation (CHP).

Table 73: Technical-economic parameters for energy from manure co-digestion (CHP)

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	3.0	
Electrical capacity	[MW_e]	1.1	
Thermal output capacity	[MW_{th_output}]	1.44	
Full load hours electrical supply	[h/a]	8,000	
Full load hours heat supply	[h/a]	4,000	
Maximum electrical efficiency		37%	
Investment costs	[€/kW_{th_input}]	1,145	€3 million
Fixed O&M costs	[€/kW_{th_input}]	85	€255,000/year
Energy content of fuel	[GJ_{biogas}/tonne]	3.4	
Feedstock costs	[€/tonne]	36.4	

Table 74 shows the base rate and several other subsidy parameters.

Table 74: Overview of subsidy parameters for co-generation, manure co-digestion

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.121
Base price for SDE+ 2016	[€/kWh]	0.029
CHP ratio	[H:E]	0.65
Combined number of full load hours	[hours/year]	5,732
Provisional correction amount in 2016	[€/kWh]	0.032
Calculation method for correction amount	(APX + TTF x 70% x CHP)/(1 + CHP)	

9.7 Heat, digestion and co-digestion of animal manure

An investment cost of 963 €/kW_{th_output} is assumed for manure co-digestion for renewable heat, including the cost of an additional boiler. The boiler supplies heat/steam at about 120°C. The cost of a gas pipe or a heat grid has not been included.

Table 75 shows the technical-economic parameters for all-feedstock digestion for co-generation (CHP).

Table 75: Technical-economic parameters for energy from manure co-digestion (heat)

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	3.0	
Full load hours heat supply	[h/a]	7,000	
Internal heat requirement	[%]	5	
Internal electricity requirement	[kWh/GJ_{output}]	5.41	
Electricity rate	[€/kWh]	0.10	
Investment costs	[€/kW_{th_output}]	963	€2.5 million
Fixed O&M costs	[€/kW_{th_output}]	74	€189,000/year
Energy content of fuel	[GJ_{biogas}/tonne]	3.4	
Feedstock costs	[€/tonne]	36.4	

Table 76 shows the base rate and several other subsidy parameters.

Table 76: Overview of subsidy parameters for manure co-digestion (heat)

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.083
Base price for SDE+ 2016	[€/kWh]	0.025
Provisional correction amount in 2016	[€/kWh]	0.031
Calculation method for correction amount	(TTF + energy tax)/gas boiler efficiency	

9.8 Digestion of more than 95% animal manure (renewable gas)

The reference system for this category has a crude biogas production of 20.5 Nm^3/h (or 11 Nm^3/h renewable gas). This is comparable to a CHP capacity of 39 kW_e, which makes the reference consistent with the reference in the advice for renewable energy for this category. The reference gas cleaning technique is based on a configuration of membranes. The heat required to heat the digester is generated by firing part of the crude biogas in a boiler. The electricity required is obtained from the grid.

Table 77 shows the technical-economic parameters for the production of renewable gas.

Table 77: Technical-economic parameters for energy from manure mono-digestion (renewable gas)

Parameter	Unit	Advice for 2016
Reference size	[$Nm^3_{gross\ crude\ biogas}/h$]	20.5
Full load hours	[h/a]	8,000
Internal heat requirement	[% biogas]	18%
Internal electricity requirement (digester)	[$kWh/Nm^3_{gross\ crude\ biogas}$]	0.13
Internal electricity requirement (gas upgrading)	[$kWh/Nm^3_{net\ crude\ biogas}$]	0.37
Electricity rate	[€/kWh]	0.16
Investment costs (digester)	[€ per $Nm^3_{gross\ crude\ biogas}/h$]	16,900
Investment costs (gas upgrading)	[€ per $Nm^3_{net\ crude\ biogas}/h$]	19,557
Fixed O&M costs (digester)	[€ per $Nm^3_{gross\ crude\ biogas}/h$]	807
Fixed O&M costs (gas upgrading)	[€ per $Nm^3_{net\ crude\ biogas}/h$]	1,892
Energy content of substrate	[GJ_{biogas}/tonne]	0.6
Feedstock costs	[€/tonne]	0
Efficiency of gas cleaning	[% methane]	99.0%

Table 78 shows the base rate and several other subsidy parameters.

Table **78**: Overview of subsidy parameters for digestion of more than 95% animal manure (renewable gas)

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.181
Base price for SDE+ 2016	[€/kWh]	0.020
Provisional correction amount in 2016	[€/kWh]	0.022
Calculation method for correction amount	TTF	

9.9 Co-generation, digestion of more than 95% animal manure (renewable gas)

The reference installation for the production of renewable heat and electricity is based on manure produced internally on the farm. Based on the energy content of the manure and the electrical efficiency of the gas engine, the reference installation delivers a net electrical output of 39 kW_e. Technically, electricity generation from digestion involves a CHP installation in which the 26 kW_{th} of heat is used entirely for the internal digestion process. Although a small part of the heat production can nevertheless be used outside the installation itself, in order to achieve a representative base rate, only electricity production has been considered as being eligible for an SDE+ allowance.

Table 79 shows the technical-economic parameters for manure co-digestion for electricity and heat.

Table 79: Technical-economic parameters for energy from manure mono-digestion (CHP)

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	0.123	
Electrical capacity	[MW_e]	0.039	
Thermal output capacity	[MW_{th_output}]	0.026	
Full load hours electrical supply	[h/a]	8,000	
Full load hours heat supply	[h/a]	0	
Maximum electrical efficiency		32%	
Investment costs	[€/kW_{th_input}]	3,348	€0.4 million
Fixed O&M costs	[€/kW_{th_input}]	198	€24,000/year
Energy content of fuel	[GJ_{biogas}/tonne]	0.63	
Feedstock costs	[€/tonne]	0	

Table 80 shows the base rate and several other subsidy parameters.

Table 80: Overview of subsidy parameters for co-generation, digestion of more than 95% animal manure

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	>0.200
Base price for SDE+ 2016	[€/kWh]	0.039
CHP ratio	H:P	n/a
Combined number of full load hours	hours/year	n/a
Provisional correction amount in 2016	[€/kWh]	0.042
Calculation method for correction amount	(APX + TTF x 70% x CHP)/(1 + CHP)	

9.10 Heat, digestion of more than 95% animal manure

The reference installation for the production of renewable heat is based on manure that is produced internally on the farm. Table 81 shows the technical-economic parameters of manure mono-digestion for heat.

Table 81: Technical-economic parameters for energy from manure mono-digestion (heat)

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	0.123	
Full load hours heat supply	[h/a]	7,000	
Internal heat requirement	[%]	5	
Internal electricity requirement	[kWh/GJ_{output}]	5.41	
Electricity rate	[€/kWh]	0.16	
Investment costs	[$€/kW_{th\_output}$]	3,916	€0.4 million
Fixed O&M costs	[$€/kW_{th\_output}$]	193	€18,000/year
Energy content of fuel	[GJ_{biogas}/tonne]	0.63	
Feedstock costs	[€/tonne]	0	

Table 82 shows the base rate and several other subsidy parameters.

Table 82: Overview of subsidy parameters for heat digestion of more than 95% animal manure

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.109
Base price for SDE+ 2016	[€/kWh]	0.025
Provisional correction amount in 2016	[€/kWh]	0.031
Calculation method for correction amount	(TTF + energy tax)/gas boiler efficiency	

10

Findings for existing installations

This chapter describes the findings for the following categories related to existing installations:

- Extended lifespan, thermal conversion ≤ 50 MWe (10.1).
- Extended lifespan, all-feedstock digestion (CHP) (10.2).
- Extended lifespan, digestion and co-digestion of animal manure (CHP) (10.3).
- Extended lifespan, all-feedstock digestion (renewable gas and heat) (10.4).
- Extended lifespan, digestion and co-digestion of animal manure (renewable gas and heat) (10.5).

The biomass prices used in this category have already been provided in sections 8.1 and 9.1.

10.1 Extended lifespan thermal conversion ≤ 50 MW_e

The 'extended life of incineration plants' category relates to projects which are covered by the current MEP scheme. When the MEP scheme ends, these installations can apply for subsidies in this category. These projects often use B-grade wood as fuel. Biomass co-firing projects are not part of this category.

In the coming years, projects in this category may consist of installations fired entirely by B-grade wood and installations fired by clean wood. The fuel price for B-grade wood is assumed to be 28 €/tonne, with an associated energy content of 13 GJ/tonne. The technical-economic parameters for the reference installation fired by B-grade wood are given in the table below. These parameters are based on a reference installation which can apply for SDE+ subsidies in 2016 (up to a maximum of 5 years before the end of the MEP).

For the reference installation, a scale of 20 MW_e and 50 MW_{th} has been assumed. The number of full load hours for the reference installation is 8,000 hours per year electricity supply and 4,000 hours per year heat supply. This is lower than the heat supply in large new projects because existing projects cannot choose a location close to a suitable heat demand. Additionally, fixed O&M costs of 163 €/$kW_{th,\ input}$ have been assumed. These costs have been indexed because of the three-year period between the application and the granting of subsidies. Bearing in mind the assumed lifespan of 12 years, ECN and DNV GL have included large-scale maintenance of the installation in the fixed O&M costs, including the replacement of the turbine and modifications to ensure the required heat transfer. The MEP did not provide subsidies for heat; for this reason, virtually all the original installations were laid out to achieve maximum electricity production and these installations do not feature heat transfer. Additional fixed O&M costs consist of staff costs, maintenance and revisions, feedstock, waste products and auxiliary fuels (excluding wood and electricity). The variable O&M costs have been included under the generic O&M item.

A maximum net electrical efficiency of 25% and a thermal efficiency of 63% have been assumed. The assumed electricity loss from the transfer of heat is in the ratio of 1:4 (electricity:heat). It is assumed that the decision on the extended lifespan subsidy is known in time, so that the existing fuel contract portfolio can be extended. For biomass categories, a subsidy duration of 12 years is assumed.

Graduated scale for overlap with MEP subsidy

Supplementary to the 'thermal conversion of biomass' category, the possibility of registering for this category before the MEP subsidy comes to an end is described here. In the current MEP regime, only the electricity supplied is subsidised, which means that investments in heat transfer are not profitable. Starting the SDE+ subsidy earlier and ending the MEP subsidy early makes it possible to supply sustainable heat. The supply of sustainable heat by BECs (bio-energy plants) leads to greater efficiency, resulting in increased sustainable energy transfer.

If the MEP is terminated early and the SDE+ subsidy then begins, the recipient will receive less subsidy in total. This is because the MEP subsidy is higher than the SDE+ subsidy. In order to prevent this shortcoming, we suggest a graduated scaleto compensate for part of the subsidy that the recipient would have received under the MEP system. The graduated scale will be incorporated into the base rate for the SDE+ incentive and the level of the scale will depend on the number of years by which the MEP incentive is shortened.

The graduated scale for the overlap with the MEP subsidy has been adjusted upwards marginally for the '3-5 years' category because modern installations with a higher electrical efficiency fall into this category. For this reason, these installations have a higher MEP deficit compared to BEC installations built previously. Compensation for this deficit has been included for these years.

Table 83 shows the base rate. In the event that the MEP income is lost prematurely, this is set off in the graduated scale in this table, which also includes other subsidy parameters.

Table 83: Overview of subsidy parameters for extended lifespan, thermal conversion ≤ 50 MW_e

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.063
Base rate with one year's MEP compensation	[€/kWh]	0.066
Base rate with two years' MEP compensation	[€/kWh]	0.068
Base rate with three years' MEP compensation	[€/kWh]	0.073
Base rate with four years' MEP compensation	[€/kWh]	0.077
Base rate with five years' MEP compensation	[€/kWh]	0.080
Base price for SDE+ 2016	[€/kWh]	0.023
CHP ratio	[H:E]	1.82
Combined number of full load hours	[hours/year]	4,429
Provisional correction amount in 2016	[€/kWh]	0.026
Calculation method for correction amount	(APX + TTF x 70% x CHP)/(1 + CHP)	

10.2 Extended lifespan, all-feedstock digestion (CHP)

The 'extended lifespan, all-feedstock digestion' category relates to digestion installations whose MEP allowance has ended. A heat supply of 4,000 full load hours has been assumed, equal to the heat supply in new CHP projects. The participants in the consultation round asked for a greater focus on the cost of renovating digesters. In view of the assumed lifespan of 12 years, ECN and DNV GL have based their calculations on large-scale maintenance of the digestion installation, including the replacement of mixers, gas roof and CHP engine. These costs have been factored into the O&M costs. Replacing the gas engine increases electrical efficiency. The net efficiency of a renovated digester is lower than a newly built installation, given the smaller scale of the MEP digesters.

Table 84 shows the technical-economic parameters for extended lifespan, all-feedstock co-digestion (CHP).

Table 84: Technical-economic parameters for energy from extended lifespan of all-feedstock digestion (CHP)

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	2.2	
Electrical capacity	[MW_e]	0.8	
Thermal output capacity	[MW_{th_output}]	0.925	
Full load hours electrical supply	[h/a]	8,000	
Full load hours heat supply	[h/a]	4,000	
Maximum electrical efficiency		37%	
Electricity loss in heat supply		-	
Investment costs	[€/kW_{th_input}]	0	€0 million
Fixed O&M costs	[€/kW_{th_input}]	158	€0.3 million/year
Energy content of substrate	[GJ/tonne]	3.4	
Feedstock price	[€/tonne]	25	

Table 85 shows the base rate and several other subsidy parameters.

Table 85: Overview of subsidy parameters for extended lifespan of all-feedstock digestion (CHP)

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.086
Base price for SDE+ 2016	[€/kWh]	0.030
CHP ratio	[H:E]	0.58
Combined number of full load hours	[hours/year]	5,855
Provisional correction amount in 2016	[€/kWh]	0.033
Calculation method for correction amount	(APX + TTF x 70% x CHP)/(1 + CHP)	

10.3 Extended lifespan, digestion and co-digestion of animal manure (CHP)

The 'extended lifespan, digestion and co-digestion of animal manure' category relates to digestion installations whose MEP allowance has ended. A heat supply of 4,000 full load hours has been assumed, equal to the heat supply in new CHP projects. The participants in the consultation round asked for a greater focus on the cost of renovating digesters. In view of the assumed lifespan of 12 years, ECN and DNV GL have based their calculations on large-scale maintenance of the digestion installation, including the replacement of mixers, gas roof and CHP engine. These costs have been factored into the O&M costs. Replacing the gas engine increases electrical efficiency. The net efficiency of a renovated digester is lower than a newly built installation, given the smaller scale of the MEP digesters.

Table 86 shows the technical-economic parameters for extended lifespan, digestion and co-digestion of animal manure.

Table 86: Technical-economic parameters for energy from extended lifespan of manure co-digestion (CHP)

Parameter	Unit	Advice for 2016	Total amount for reference
Input capacity	[MW_{th_input}]	2.2	
Electrical capacity	[MW_e]	0.8	
Thermal output capacity	[MW_{th_output}]	0.925	
Full load hours electrical supply	[h/a]	8,000	
Full load hours heat supply	[h/a]	4,000	
Maximum electrical efficiency		37%	
Electricity loss in heat supply		-	
Investment costs	[€/kW_{th_input}]	0	€0 million
Fixed O&M costs	[€/kW_{th_input}]	158	€0.3 million/year
Energy content of substrate	[GJ/tonne]	3.4	
Feedstock price	[€/tonne]	36.4	

Table 87 shows the base rate and several other subsidy parameters.

Table 87: Overview of subsidy parameters for extended lifespan for digestion and co-digestion of animal manure (CHP)

	Unit	SDE+ 2016 advice
Base rate for SDE+ 2016	[€/kWh]	0.108
Base price for SDE+ 2016	[€/kWh]	0.030
CHP ratio	[H:E]	0.58
Combined number of full load hours	[hours/year]	5,855
Provisional correction amount in 2016	[€/kWh]	0.033
Calculation method for correction amount	(APX + TTF x 70% x CHP)/(1 + CHP)	

10.4 Extended lifespan, all-feedstock digestion (renewable gas and heat)

Installations for all-feedstock digestion can also opt not to replace the gas engine but to connect the installation to a green gas or heat hub, so that instead of electricity, renewable gas is produced or heat is supplied.

Reference systems for the production of crude biogas
When determining the technical-economic parameters for the production of crude biogas, the costs of CO_2 separation are not included, whereas the costs of limited gas cleaning to remove hydrogen sulphide or ammonia are included. In addition, it has been assumed that part of the crude biogas in a boiler is fired to supply heat for the digester. In order to extend the lifespan, analogous to the CHP option, the costs of renovation (excluding the CHP replacement) have been included in the O&M costs.

Table 88 shows the technical-economic production parameters for a green gas or heat hub based on existing all-feedstock digesters. In the case of supply to a heat hub (see appendix A), the number of full load hours is limited by the full load hours of the heat supplied by the hub, i.e. 7,000 hours/year.

Table 88: Technical-economic parameters for energy from extended lifespan of all-feedstock digestion (crude biogas)

Parameter	Unit	Advice for 2016	Total amount for reference
Reference size	[$Nm^3_{gross\ crude\ biogas}$/h]	370	
Full load hours	[h/a]	8000*	
Internal heat requirement	[% biogas]	5%	
Internal electricity requirement (digester)	[kWh/$Nm^3_{gross\ crude\ biogas}$]	0.12	
Internal electricity requirement (gas upgrading)	[kWh/$Nm^3_{net\ crude\ biogas}$]	0.13	
Electricity rate	[€/kWh]	0.10	
Investment costs (digester)	[€ per $Nm^3_{gross\ crude\ biogas}$/h]	0	€0 million
Investment costs (gas upgrading)	[€ per $Nm^3_{net\ crude\ biogas}$/h]	385	combined
Fixed O&M costs (digester)	[€ per $Nm^3_{gross\ crude\ biogas}$/h]	480	€0.19 million/year
Fixed O&M costs (gas upgrading)	[€ per $Nm^3_{net\ crude\ biogas}$/h]	38	combined
Energy content of substrate	[GJ_{biogas}/tonne]	3.4	
Feedstock costs	[€/tonne]	25	

* 7000 full load hours for delivery to a heat hub.

Table 89 shows the base rate and several other subsidy parameters. This includes the cost of crude biogas production and the cost of the supply hub (see Appendix A).

Table 89: Overview of subsidy parameters for extended lifespan, all-feedstock digestion (renewable gas and heat)

	Unit	Advice for SDE+ 2016 renewable gas	Advice for SDE+ 2016 heat
Base rate for SDE+ 2016	[€/kWh]	0.059	0.056
Base price for SDE+ 2016	[€/kWh]	0.020	0.014
Provisional correction amount in 2016	[€/kWh]	0.022	0.017
Calculation method for correction amount		TTF	TTF x 70%

10.5 Extended lifespan, digestion and co-digestion of animal manure (renewable gas and heat)

Installations for digestion and co-digestion of manure can also opt not to replace the gas engine but to connect the installation to a hub, so that instead of generating electricity, it produces renewable gas or it supplies heat.

Reference systems for the production of crude biogas
When determining the technical-economic parameters for the production of crude biogas, the costs of CO_2 separation are not included, whereas the costs of limited gas

cleaning to remove hydrogen sulphide or ammonia are included. In addition, it has been assumed that part of the crude biogas in a boiler is fired to supply heat for the digester. In order to extend the lifespan, analogous to the CHP option, the costs of renovation (excluding the CHP replacement) have been included in the O&M costs.

Table 90 shows the technical-economic production parameters for a green gas or heat hub based on existing manure co-digesters. In the case of supply to a heat hub (see appendix A), the number of full load hours is limited by the full load hours of the heat supply by the hub, i.e. 7000 hours/year.

Table 90: Technical-economic parameters for energy from extended lifespan of manure digestion and co-digestion (crude biogas)

Parameter	Unit	Advice for 2016	Total amount for reference
Reference size	[$Nm^3_{gross\ crude\ biogas}$/h]	370	
Full load hours	[h/a]	8,000	
Internal heat requirement	[% biogas]	5%	
Internal electricity requirement (digester)	[kWh/$Nm^3_{gross\ crude\ biogas}$]	0.12	
Internal electricity requirement (gas upgrading)	[kWh/$Nm^3_{net\ crude\ biogas}$]	0.13	
Electricity rate	[€/kWh]	0.10	
Investment costs (digester)	[€ per $Nm^3_{gross\ crude\ biogas}$/h]	0	€0 million combined
Investment costs (gas upgrading)	[€ per $Nm^3_{net\ crude\ biogas}$/h]	385	
Fixed O&M costs (digester)	[€ per $Nm^3_{gross\ crude\ biogas}$/h]	480	€0.19 million/year combined
Fixed O&M costs (gas upgrading)	[€ per $Nm^3_{net\ crude\ biogas}$/h]	38	
Energy content of substrate	[GJ_{biogas}/tonne]	3.4	
Feedstock costs	[€/tonne]	36.4	

Table 91 shows the base rate and several other subsidy parameters. This includes the cost of crude biogas production and the cost of the supply hub (see Appendix A).

Table 91: Overview of subsidy parameters for extended lifespan of digestion and co-digestion of animal manure (renewable gas and heat)

	Unit	Advice for SDE+ 2016 renewable gas	Advice for SDE+ 2016 heat
Base rate for SDE+ 2016	[€/kWh]	0.071	0.071
Base price for SDE+ 2016	[€/kWh]	0.020	0.014
Provisional correction amount in 2016	[€/kWh]	0.022	0.017
Calculation method for correction amount		TTF	TTF x 70%

11

Overview of base rates

The technical-economic parameters from the previous chapters are important information for calculating the base rates based on the stylised ECN cash flow model, which was also used for the advice in previous years. The cash flow model, completed for each category, can be downloaded from the ECN website: http://www.ecn.nl/nl/projecten/sde/sde-2016.

The resulting draft base rates for SDE+ 2016 are shown in Table 92 to Table 97. As stated in Chapter 2, all base rates for the SDE+ 2016 are given in euros per kWh. The designations E, G, H and CHP are used to denote whether the category in question refers to renewable electricity, gas, heat or combined heat and power plants. For comparison, the base rates from the SDE+ 2015 Base Rates Final advice have also been included in the table[10]. Base rates higher than 0.200 €/kWh have been calculated indicatively and denoted with the rate > 0.200 €/kWh.

10 https://www.ecn.nl/publicaties/ECN-E--14-035.

Table 92: Advised base rates for SDE+ 2016: hydro-electric, wind and solar energy (amounts in €/kWh)[11]

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours	Advised base rate for SDE+ 2015
Hydropower, height of fall ≥ 50 cm	E	0.173	5,700	0.175
Hydropower, height of fall ≥ 50 cm, renovation	E	0.108	2,600	0.067
Free tidal current energy, height of fall < 50 cm	E	>0.200	3,700	0.275
Osmosis	E	>0.200	8,000	0.585
Photovoltaic solar panels ≥ 15 kW_p and connection >3x80A	E	0.128	950	0.141
Solar thermal, aperture area ≥ 100 m^2	H	0.103	700	0.137
Onshore wind, ≥ 8 m/s	E	0.070	n/a	0.074
Onshore wind, ≥ 7.5 and < 8 m/s	E	0.076	n/a	0.081
Onshore wind, ≥ 7.0 and < 7.5 m/s	E	0.082	n/a	0.086
Onshore wind, < 7.0 m/s	E	0.093	n/a	0.098
Wind on interconnecting water defences, ≥ 8 m/s	E	0.075	n/a	0.081
Wind on interconnecting water defences, ≥ 7.5 and < 8 m/s	E	0.082	n/a	0.088
Wind on interconnecting water defences, ≥ 7.0 and < 7.5 m/s	E	0.087	n/a	0.094
Wind on interconnecting water defences, < 7.0 m/s	E	0.099	n/a	0.107
Wind on lake, water ≥ 1 km^2	E	0.114	n/a	0.114

Table 93: Advised base rates for SDE+ 2016: geothermal energy (amounts in €/kWh)

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours (power/heat)	Full load hours combined	Heat/power ratio	Advised base rate for SDE+ 2015
Geothermal heat, depth ≥ 500 metres	H	0.056	5,500	-	-	0.052
Geothermal heat, depth ≥ 3,500 metres	H	0.062	7,000	-	-	0.055
Geothermal co-generation, depth ≥ 500 metres	CHP	0.112	5,000/4,000	4,091	8.00	0.098

11 No full load hours have been included for the categories relating to wind energy in view of the fact that since SDE+ 2015, the generic full load hours cap has been scrapped.

Table 94: Advised base rates for SDE+ 2016: water purification plants (amounts in €/kWh)

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours (power/ heat)	Full load hours combined	Heat/power ratio	Advised base rate for SDE+ 2015
Waste water treatment plant (WWTP) - thermophilic digestion of secondary sludge	CHP	0.060	8,000/4,000	5,729	0.66	0.061
WWTP - thermal pressure hydrolysis	E	0.093	8,000	-	-	0.095
WWTP (renewable gas)	G	0.032	8,000	-	-	0.034

Table 95: Advised base rates for SDE+ 2016: incineration and gasification of biomass (amounts in €/kWh)

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours (power/ heat)	Full load hours combined	Heat/power ratio	Advised base rate for SDE+ 2015
Biomass gasification (≥ 95% biogenic)	G	0.151	7,500	-	-	0.139
Existing capacity for direct and indirect co-firing	E	0.107	5,000/6,000	5,839	-	0.108
New capacity for direct co-firing	E	0.114	7,000	-	-	0.115
Boiler fired by solid or liquid biomass 0.5-5 MW_{th}	H	0.052	4,000	-	-	0.051
Boiler fired by solid or liquid biomass ≥5 MW_{th}	H	0.043	7,000	-	-	0.043
Boiler fired by liquid biomass	H	0.071	7,000	-	-	0.072
Heat, wood pellets	H	0.057	7,000	-	-	0.054
Thermal conversion of biomass, > 50 MW_{th}	CHP	0.077	7,500/7,500	7,500	2.99	0.084[12]
Thermal conversion of biomass, ≤ 50 MW_{th}	CHP	0.143	8,000/4,000	4,241	2.44	0.144[11]

* In relation to existing capacity for direct and indirect co-firing, 5,000/6,000 stands for 5,000 full load hours of direct co-firing and 6,000 full load hours of indirect co-firing.

12 In the SDE+2015, the category limit was 10 MW_e.

Table 96: Advised base rates for SDE+ 2016: digestion of biomass (amounts in €/kWh)

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours (power/ heat)	Full load hours combined	Heat/power ratio	Advised base rate for SDE+ 2015
All-feedstock digestion (renewable gas)	G	0.060	8,000	-	-	0.063
Co-generation, all-feedstock digestion	CHP	0.087	8,000/ 4,000	5,742	0.65	0.095
Heat, all-feedstock digestion	H	0.060	7,000	-	-	0.053
Digestion and co-digestion of animal manure (renewable gas)	G	0.080	8,000	-	-	0.083
Co-generation, digestion and co-digestion of animal manure	CHP	0.121	8,000/ 4,000	5,732	0.65	0.121
Heat, digestion and co-digestion of animal manure	H	0.083	7,000	-	-	0.080
Digestion of more than 95% animal manure (renewable gas)	G	0.181	8,000	-	-	0.136
Co-generation, digestion of more than 95% animal manure (renewable gas)	CHP	>0.200	8,000	-	-	0.305
Heat, digestion of more than 95% animal manure	H	0.109	7,000	-	-	0.106

Table 97: Advised base rates for SDE+ 2016: existing installations (amounts in €/kWh)

Category	Energy carrier	Advised base rate for SDE+ 2016	Full load hours (power/ heat)	Full load hours combined	Heat/power ratio	Advised base rate for SDE+ 2015
Extended lifespan, thermal conversion ≤ 50 MW_e	CHP	0.063	8,000/ 4,000	4,429	1.82	0.064
Extended lifespan all-feedstock digestion, co-generation	CHP	0.086	8,000/ 4,000	5,855	0.58	0.087
Extended lifespan co-generation, digestion and co-digestion of animal manure	CHP	0.108	8,000/ 4,000	5,855	0.58	0.108
Extended lifespan all-feedstock digestion (renewable gas)	G	0.059	8,000	-	-	0.064
Extended lifespan all-feedstock digestion (heat)	H	0.056	7,000	-	-	0.058
Extended lifespan digestion and co-digestion of animal manure (renewable gas)	G	0.071	8,000	-	-	0.076
Extended lifespan digestion and co-digestion of animal manure (heat)	H	0.071	7,000	-	-	0.072

Abbreviations

APX	Amsterdam Power eXchange, market index for electricity (day ahead)
WWTP	Waste water treatment plant
BEC	Bio-energy plant
CAPEX	Capital Expenditures, investment costs
CAR	Construction all risk insurance
EZ	Dutch Ministry of Economic Affairs
LEI	Agricultural Economics Research Institute
MEP	Environmental Quality of Electricity Production
O&M	Operation and Maintenance
OPEX	Operating Expenditures
ORC	Organic Rankine Cycle
RED	Reversed Electrodialysis
FGD	Flue gas desulphurisation installation
RVB	Central Government Real Estate Agency (*Rijksvastgoedbedrijf*)
RWZI	Waste Water Treatment Plant (*Rioolwaterzuiveringsinstallatie*)
SDE	Dutch Renewable Energy Production Support Scheme
SNCR	Selective non-catalytic reduction installation
SNG	Substitute Natural Gas or Synthetic Natural Gas
TTF	Title Transfer Facility, market index for gas (futures market)
WACC	Weighted Average Cost of Capital
CHP	Combined Heat and Power

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Appendix A. Hubs and production of crude biogas

A.1. Introduction

Unlike renewable gas, biogas does not comply with the specifications for feeding into the natural gas grid. Primarily consisting of methane and carbon dioxide, which is produced by various digestion installations, crude biogas can be transported to a central point through a low-pressure pipeline. In these so-called hubs, the biogas is used for the production of electricity and/or heat. It can also be purified to produce renewable gas. For most categories, the cost of processing to produce electricity and/or heat or renewable gas at the location itself is included. For a few categories, processing via a hub is more reasonable (as for extended lifetime of all-feedstock digesters, manure co-digesters and agricultural digesters which can choose to not merely replace the CHP). For this reason, this section shows the technical-economic parameters of hubs by way of explanation of the parameters in the chapter on digestion.

Most base rates are calculated using the cost structure of an independent installation, i.e. without a hub connection.

A.2. Description of reference heat hub

The technical-economic parameters for the reference heat hub including biogas pipeline are shown in Table 98. These parameters result in a cost price for a heat hub of 0.003 €/kWh.

Table 98: Technical-economic parameters for heat hub

Parameter	Unit	Advice 2016	Total amount for reference
Input capacity	[MW_{th_input}]	12.7	
Full load hours heat supply	[h/a]	7,000	
Internal heat requirement	[%]	0	
Internal electricity requirement	[kWh/GJ_{output}]	0.8	
Electricity rate	[€/kWh]	0.10	
Investment costs	[$€/kW_{th\_output}$]	60	€0.7 million
Fixed O&M costs	[$€/kW_{th\_output}$]	1.3	€15,000/year

A.3. Description of reference green gas hub

The reference system for a green gas hub has a crude biogas input of 2200 Nm^3/h (or 1440 Nm^3/h renewable gas). The reference gas purification technology chosen is membrane technology, in view of the fact that this technology has been used for several recent renewable gas projects. This technology works at high pressures in order to achieve the separation between CH_4 and CO_2. The CO_2 flow can be further cooled into the by-product liquid CO_2 using this technology. However, when calculating the base rate, no account has been taken of the additional investment and O&M costs of this step. The required electricity is purchased externally.

The technical-economic parameters for the reference green gas hub, including biogas pipeline and green gas compression to 40 bar, are shown in Table 99. These parameters result in a cost price for a green gas hub of 0.017 €/kWh.

Table 99: Technical-economic parameters for green gas hub

Parameter	Unit	Advice 2016	Total amount for reference
Reference size	[$Nm^3_{\text{gross crude biogas}}$/h]	2,200	
Full load hours	[h/a]	8,000	
Internal electricity requirement (gas upgrading)	[kWh/$Nm^3_{\text{net crude biogas}}$]	0.45	
Electricity rate	[€/kWh]	0.10	
Investment costs (digester)	[€ per $Nm^3_{\text{gross crude biogas}}$/h]	0	€4 million
Investment costs (gas upgrading)	[€ per $Nm^3_{\text{net crude biogas}}$/h]	1,750	combined
Fixed O&M costs (digester)	[€ per $Nm^3_{\text{gross crude biogas}}$/h]	0	€0.187 million/year
Fixed O&M costs (gas upgrading)	[€ per $Nm^3_{\text{net crude biogas}}$/h]	85	combined
Efficiency of gas cleaning	[% methane]	99.9%	

Appendix B. Overview of base rates and correction amounts

The base rates and provisional correction amounts for 2016 are set out in the following tables. The calculation methods for these base rates are included in Kraan and Lensink, 2015 and for the correction amounts in Lensink and Van Zuijlen, 2015.

Table 102: Base rate and provisional correction amount SDE+ 2016: hydropower, wind and solar energy.

Category	Base rate [€/kWh]	Correction amount [€/kWh]
Hydropower, height of fall ≥ 50 cm	0.039	0.042
Hydropower, height of fall ≥ 50 cm, renovation	0.039	0.042
Free tidal current energy, height of fall < 50 cm	0.039	0.042
Osmosis	0.039	0.042
Photovoltaic solar panels, ≥ 15 kW_p and connection >3x80A	0.035	0.044
Solar thermal, aperture area ≥ 100 m^2	0.025	0.031
Onshore wind, ≥ 8 m/s	0.030	0.038
Onshore wind, ≥ 7.5 and < 8 m/s	0.030	0.038
Onshore wind, ≥ 7.0 and < 7.5 m/s	0.030	0.038
Onshore wind, < 7.0 m/s	0.030	0.038
Wind on interconnecting water defences, ≥ 8 m/s	0.030	0.038
Wind on interconnecting water defences, ≥ 7.5 and < 8 m/s	0.030	0.038
Wind on interconnecting water defences, ≥ 7.0 and < 7.5 m/s	0.030	0.038
Wind on interconnecting water defences, < 7.0 m/s	0.030	0.038
Wind on lake, water ≥ 1 km^2	0.030	0.038

Table 103: Base rate and provisional correction amount SDE+ 2016: geothermal energy

Category	Base rate [€/kWh]	Correction amount [€/kWh]
Geothermal heat, depth ≥ 500 metres	0.014	0.017
Geothermal heat, depth ≥ 3,500 metres	0.014	0.017
Geothermal co-generation, depth ≥ 500 metres	0.017	0.020

Table 104: Base rate and provisional correction amount SDE+ 2016: water purification plants

Category	Base rate [€/kWh]	Correction amount [€/kWh]
Waste water treatment plant (WWTP) - thermophilic digestion of secondary sludge	0.029	0.032
WWTP - thermal pressure hydrolysis	0.039	0.042
WWTP (renewable gas)	0.020	0.022

Table 105: Base rate and provisional correction amount SDE+ 2016: incineration and gasification of biomass

Category	Base rate [€/kWh]	Correction amount [€/kWh]
Biomass gasification (≥95% biogenic)	0.020	0.022
Existing capacity for direct and indirect co-firing	0.039	0.042
New capacity for direct co-firing	0.039	0.042
Boiler fired by solid or liquid biomass 0.5-5 MW_{th}	0.025	0.031
Boiler fired by solid or liquid biomass ≥5 MW_{th}	0.014	0.017
Boiler fired by liquid biomass	0.025	0.031
Heat, wood pellets	0.014	0.017
Thermal conversion of biomass, > 50 MW_{th}	0.020	0.023
Thermal conversion of biomass, ≤ 50 MW_{th}	0.021	0.024

Table 106: Base rate and provisional correction amount SDE+ 2016: digestion of biomass

Category	Base rate [€/kWh]	Correction amount [€/kWh]
All-feedstock digestion (renewable gas)	0.020	0.022
Co-generation, all-feedstock digestion	0.029	0.032
Heat, all-feedstock digestion	0.025	0.031
Digestion and co-digestion of animal manure (renewable gas)	0.020	0.022
Co-generation, digestion and co-digestion of animal manure	0.029	0.032
Heat, digestion and co-digestion of animal manure	0.025	0.031
Digestion of more than 95% animal manure (renewable gas)	0.020	0.022
Co-generation, digestion of more than 95% animal manure (renewable gas)	0.039	0.042
Heat, digestion of more than 95% animal manure	0.025	0.031

Table 107: Base rate and provisional correction amount SDE+ 2016: existing installations

Category	Base rate [€/kWh]	Correction amount [€/kWh]
Extended lifespan, thermal conversion ≤ 50 MWe	0.023	0.026
Extended lifespan all-feedstock digestion, co-generation	0.030	0.033
Extended lifespan co-generation, digestion and co-digestion of animal manure	0.030	0.033
Extended lifespan all-feedstock digestion (renewable gas)	0.020	0.022
Extended lifespan all-feedstock digestion (heat)	0.014	0.017
Extended lifespan digestion and co-digestion of animal manure (renewable gas)	0.020	0.022
Extended lifespan digestion and co-digestion of animal manure (heat)	0.014	0.017

Appendix C. Basic information for SDE+

The following text has been taken virtually verbatim from the website RVO.nl (Netherlands Enterprise Agency) (2015) and the document *Nationaal actieplan voor energie uit hernieuwbare bronnen* (National action plan for energy from renewable sources) NREAP (Dutch Government, 2010).

Box 1: Basic information for SDE+

General
The Dutch Renewable Energy Production Support Scheme (SDE+) stimulates the production of sustainable energy. Sustainable energy is generated from clean, inexhaustible sources and is therefore also known as 'renewable energy'.

What is SDE+?
SDE+ is an operating incentive. In other words, producers receive a subsidy for the sustainable energy they generate and not for the purchase of the production plant, as in the case of an investment subsidy. SDE+ is focused on companies and institutions that want to produce sustainable energy. The Dutch Government is excluded from participating in SDE+. The cost price of sustainable energy is higher than that of grey energy. As such, the production of sustainable energy is not always profitable.

The SDE scheme reimburses the difference between the cost price of grey energy and that of sustainable energy over a period of 5, 8, 12 or 15 years, depending on the technology. How much subsidy you can receive depends on the technology and the quantity of sustainable energy you produce. The SDE+ has a single budget for all categories and is opened in phases. In the first phase, the 'cheaper' technologies can apply for subsidies. The subsidy increases per phase. In addition, in certain cases it is possible to submit an application in a so-called free category.

What does SDE+ apply to?
In 2015, SDE+ was opened for the production of:

- Renewable electricity;
- Renewable gas;
- Renewable heat or a combination of renewable heat and electricity (CHP).

For energy from:

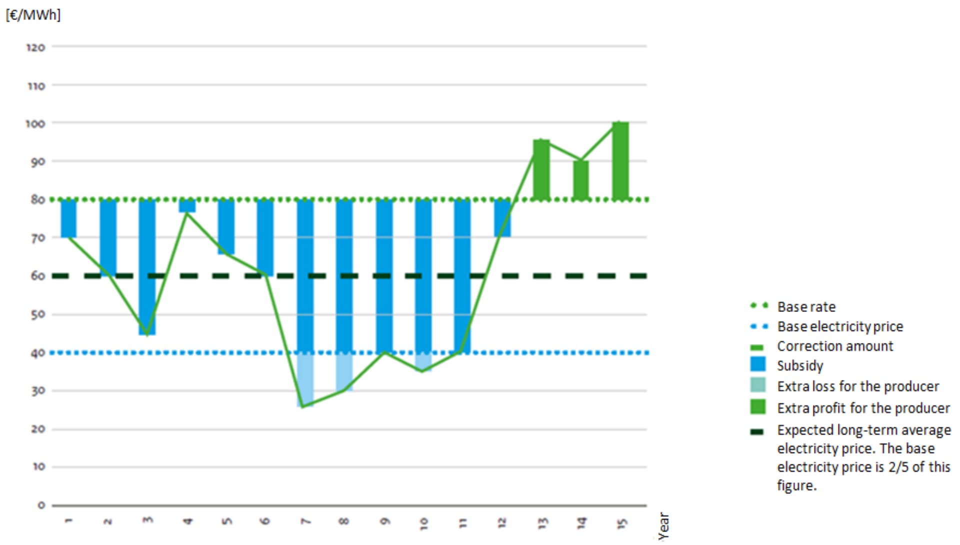
- Biomass
- Geothermal

- Water
- Wind
- Solar

The SDE+ contribution
The cost price of the production of green energy is reflected in the base rate for the technology. The yield of the grey/other energy is reflected in the correction amount. SDE+ reimburses the difference between the cost price of green energy and the yield of the grey/other energy: SDE+ contribution = base rate - correction amount.
This means that the level of the SDE+ contribution is dependent on changes in the energy price. At a higher energy price, you receive less SDE+ but you receive more from your energy customer. At a lower energy price, you receive more SDE+ and less from your energy customer. The subsidy that the Netherlands Enterprise Agency (*Rijksdienst voor Ondernemend Nederland*) allocates to you in the decision is a maximum amount over the entire term of the subsidy (5, 8, 12 or 15 years). This maximum is based on the capacity submitted and the maximum number of full load hours for the technology. The base energy price is used to calculate the amount of the allowance. The base energy price is the lower limit for the correction amount. The correction amount cannot be lower than the base energy price. If the correction amount is equal to the base energy price, the maximum subsidy has been reached. The ultimate size of the subsidy is calculated each year on the basis of the quantity of energy you produce and the level of the energy price. The subsidy applies up to a maximum number of full load hours and has a maximum term, depending on the technology.

Source: RVO, 2015.

Figure 4: SDE+ contribution = base rate - correction amount.



Source: Dutch Government, 2010.

Pillars of the SDE+

1 Single integrated budget ceiling

A single subsidy ceiling has been set for all categories. In 2015, 3.5 billion euros is available for supporting projects. If more applications are received in a day than there is remaining budget available, the applications are ranked by order of base rate. The application with the lowest base rate is first on the list. If the budget limit falls between applications with the same base rates, lots are drawn between them.

2 Phased opening

The SDE+ is opened in a phased manner. In 2015, nine phases will be opened in the period between 9:00 on 31 March and 17:00 on 17 December 2015. Each phase has a maximum base rate, rising from 0.070 €/kWh (0.055 €/kWh for renewable gas) in phase 1 to 0.150 €/kWh (0.118 €/kWh for renewable gas) in phase 9. Each technology has a maximum base rate above which no subsidy is paid. In phase 1, cost-effective technologies with a base rate lower than or equal to 0.070 €/kWh can submit applications. Compared to technologies with a higher maximum base rate, phase 1 applicants have a greater chance that there will be sufficient budget available.

3 Maximum base rate

The SDE+ 2015 is based on a maximum base rate of 0.150 €/kWh (0.118 €/kWh for renewable gas). Technologies that can produce sustainable energy for this amount or less are eligible for subsidy.

4 Free category

In each phase, there is a free category. This allows innovative entrepreneurs who are able to produce more cheaply than the base rate calculated for the technology in question to gain access to SDE+. Projects in the free category are subject to a base rate which is the same as the upper limit of the relevant phase in which subsidy was applied for. A condition is that this amount must be lower than the base rate for the technology in question. In this way, the free category also offers scope to a number of technologies whose costs are higher on average than 0.150 €/kWh (converted to 0.118 €/kWh for renewable gas).

Source: RVO, 2015.

Appendix D. External review

International Institute for Sustainability Analysis and Strategy

Scientific Director:
Uwe R. Fritsche uf@iinas.org
Administrative Director:
Thomas Stetz ts@iinas.org

Offices:
Heidelberger Str. 129 ½
D-64285 Darmstadt, Germany
ph +49 (6151) 850-6077
fax +49 (6151) 850-6080

Marienstraße 19-20
D-10117 Berlin, Germany
ph +49 (30) 28482-190
info@iinas.org

Review of the SDE+ 2016 Cost Assessment: Final Statement

prepared for MINEZ

prepared by

Uwe R. Fritsche
Scientific Director, IINAS
Hans-Werner Gress, Leire Iriarte
Research Fellows, IINAS

Darmstadt, Madrid, September 2015

1 Background

The Ministerie van Economische Zaken (MINEZ) asked IINAS to review the SDE+ Cost Assessment prepared by ECN and DNV[1].

IINAS prepared a **draft** of respective findings, provided additional material to substantiate issues raised (articles and studies), and discussed those with ECN who prepared a brief written response to the draft.

This response was discussed further bilaterally based on which this final review statement was prepared.

2 Results of the Review

The analysis of the core parameters of the SDE+ Cost Assessment showed that nearly all data chosen by ECN are within reasonable range of respective data from other sources (ongoing EU projects; IEA and IRENA; Austrian, German and Swiss data). IINAS made specific comments on fuel prices (biomass feedstock cost), investment and fixed cost data (geothermal, solar, wind), as well as efficiencies of biomass systems. All issues raised were discussed with ECN which led to some adjustments of the previous data (e.g. for small-scale biomass cogeneration).

The only two issues remaining unresolved are the efficiency reduction of both existing and new coal powerplants due to biomass co-firing, and the additional investment cost of co-firing for new coal powerplants. The efficiency reduction rate of 0.2 % per 10% co-firing (i.e. 0.4% for the assumed co-firing rate of 20%) **seems excessive**, as experiences in Denmark, Germany and the UK with large-scale co-firing of pellets indicate **no relevant efficiency** loss. For indirect co-firing, the lower heating value of SNG may result in a small change of flame temperature and respective drop of efficiency, but this – again for low co-firing ratios – seems **also negligible**.

Furthermore, the investment for solid biomass co-firing of 450 €/kW$_{el}$ seems too high for new coal plants, as other studies assume costs of 300 €/kW$_{el}$ or less.

As ECN indicated that its data are based on (unpublished) Dutch data, we recommend to analyze these two issues in more detail in future work for SDE+.

1 "Pre-final advice base rates SDE+ 2016", ECN-E--15-029 by C.L. van Zuijlen & S.M. Lensink (ECN), dated July 16, 2015

Appendix E. Afterword

In this afterword, ECN and DNV GL respond to the reviewer's comments. First of all, the relevant researchers of ECN and DNV GL would like to thank Mr U.R. Fritsche and his colleagues for the constructive talks and the accompanying written comments. After exchanging information, ECN and DNV GL have made several adjustments and clarified certain aspects. The reviewer decided to insert a comment in the advice of ECN and DNV GL on two points, namely the effects of co-firing biomass on the energy efficiency of a coal-fired power plant and the specific investment costs needed for the biomass installation to be able to partly supply the coal-fired power plant with biomass. These two comments did not prompt ECN and DNV GL to make any adjustment to the advice, as explained below.

Effects on energy efficiency

The possible influence of a different fuel on the net efficiency of the coal-fired power plant is obvious; the main question is the extent of that effect. Open literature, including the literature put forward by the reviewer, provides a reasonably simple picture of slight declines of efficiency in co-fired installations, although other sources generally claim that the effect is negligible. It is possible to demonstrate from practical experience in the Netherlands that the effect in the existing coal-fired power plant is real. This is more uncertain for new coal-fired power plants, as a result of which the supercritical high efficiency design constitutes an additional undetermined factor. ECN and DNV GL believe that the current assumption can be properly defended and that the reviewer's statement (i.e. that there is no significant decline in the net efficiency of a coal-fired power plant) reflects the less likely lower value of the margin of uncertainty.

Specific investment costs of a biomass installation

In relation to the investment costs of the biomass installation, the reviewer recommends reducing the parameter value from 450 €/kW$_e$ to 300 €/kW$_e$. Based on market information (including detailed specifications), ECN and DNV GL expect that there will be some spread in the additional costs that must be incurred for co-firing in Dutch coal-fired power plants. This spread arises because of operating and location-specific circumstances, as a result of which these costs may end up being higher or lower. The value mentioned by the reviewer is within the range that ECN and DNV GL deem likely. The suggested value is at the bottom of this range.

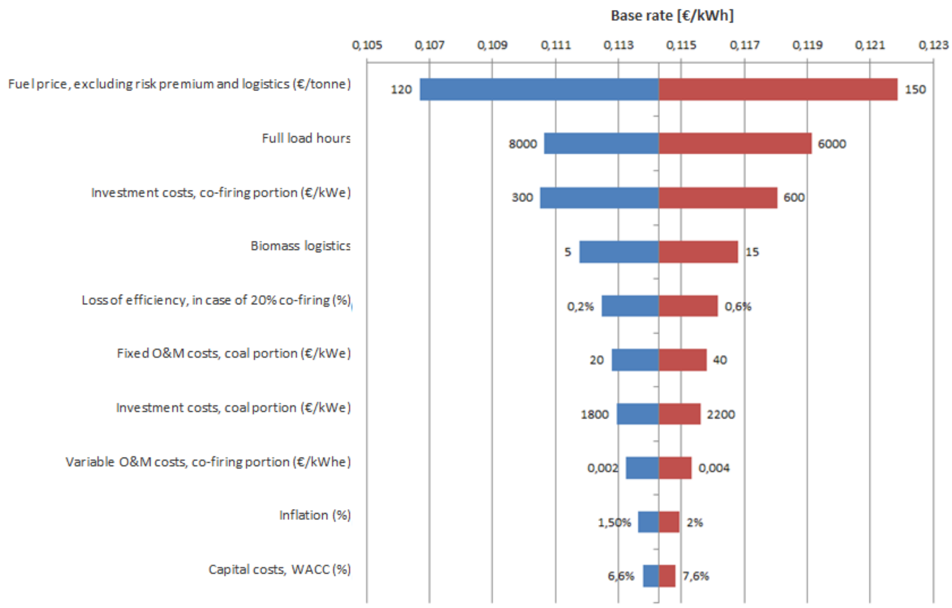
Basic principle of the SDE

ECN and DNV GL believe that the reviewer's suggested values for both comments lie at the bottom of the range. The basic principle of the SDE is that the base rate must suffice for most projects. ECN and DNV GL therefore do not feel it is in keeping with this basic principle to adjust the calculation and take the best case as a starting point for conversion efficiency and investment costs. The assumptions chosen for the loss in efficiency and the investment costs for the biomass installation are in keeping with this basic principle.

Uncertainty and ranges in the base rate for co-firing
Lastly, ECN and DNV GL note that the effect of the range in these two assumptions on the base rate is relatively limited in comparison to some other parameters for biomass co-firing. Figure 5 details a sensitivity analysis, which shows the influence of the different components that determine the base rate for co-firing. The biomass price and the number of full load hours have the greatest impact on the base rate.

The parameter with the most influence on the base rate is the biomass price. This biomass price depends on various factors, such as the cost of long-term contracting, the uncertainty in foreign exchange rates and the costs of sustainability criteria. A risk premium has been included in the calculation in order to do justice to these risks. The effect of this premium is also substantially higher than the range in the reviewer's suggested parameters.

Figure 5: Sensitivity analysis across different parameters of the base rate for co-firing



ECN

Westerduinweg 3
1755 LE Petten
The Netherlands

P.O. Box 1
1755 ZG Petten
The Netherlands

T +31 88 515 4949
F +31 88 515 8338
info@ecn.nl
www.ecn.nl